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BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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JASON R. THACKSTON

REPRESENTING AVISTA CORPORATION

2020 Electric Integrated Resource Plan

Safe Harbor Statement

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the Company's control, and many of which could have a significant impact on the Company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

For a further discussion of these factors and other important factors, please refer to the Company's reports filed with the Securities and Exchange Commission. The forward-looking statements contained in this document speak only as of the date hereof. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the Company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

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2020 Electric IRP Introduction

Avista has a 130-year tradition of innovation and a commitment to providing safe, reliable, low-cost, clean energy to our customers. We meet this commitment through a diverse mix of generation and demand side resources.

The 2020 Integrated Resource Plan (IRP) continues our legacy by looking 25 years into the future to determine the energy needs of our customers. The IRP analyzes and outlines a strategy to meet demand and clean energy requirements using demand and supply side resources.

Summary

The 2020 IRP shows Avista has adequate resources between owned and contractually controlled generation to meet customer needs through 2025. New renewable energy, energy storage, demand response, energy efficiency, and upgrades to existing hydropower and biomass plants are integral to our plan.

Changes

Major changes from the 2017 IRP include:

- The energy forecast grows 0.3 percent per year, replacing the 0.5 percent annual growth rate in the last IRP.
- Peak load growth is 0.3 percent in the winter and 0.4 percent in the summer.
- Energy efficiency meets 71 percent of new load growth compared to 53 percent in the 2017 IRP.

Highlights

Some highlights of the 2020 IRP include:

- The resource strategy reduces greenhouse gas emissions between 80-90 percent from present levels.
- A combination of new wind, storage, and demand response will meet the capacity losses from coal and natural gas-fired generation by 2026.
- A larger portfolio of new resources than in previous IRPs to meet expected resource retirements and new renewable energy goals.
- As much as 300 MW of new renewable generation by 2023 and a further 200 MW by 2027.

IRP Process

Each IRP is a thoroughly researched and data-driven document identifying a Preferred Resource Strategy to meet customer needs while balancing costs and risk measures with environmental goals and mandates. Avista's professional energy analysts use sophisticated modeling tools and input from over 75 participants to develop each plan. The participants in the public process include customers, academics, environmental organizations, government agencies, consultants, utilities, elected officials, state utility commission stakeholders, and other interested parties.

Conclusion

This document is mostly technical in nature. The IRP has an Executive Summary and chapter highlights at the beginning of each section to help guide the reader. Avista expects to begin developing the 2021 IRP in early 2020. Stakeholder involvement is encouraged and interested parties may contact John Lyons at (509) 495-8515 or john.lyons@avistacorp.com for more information on participating in the IRP process.

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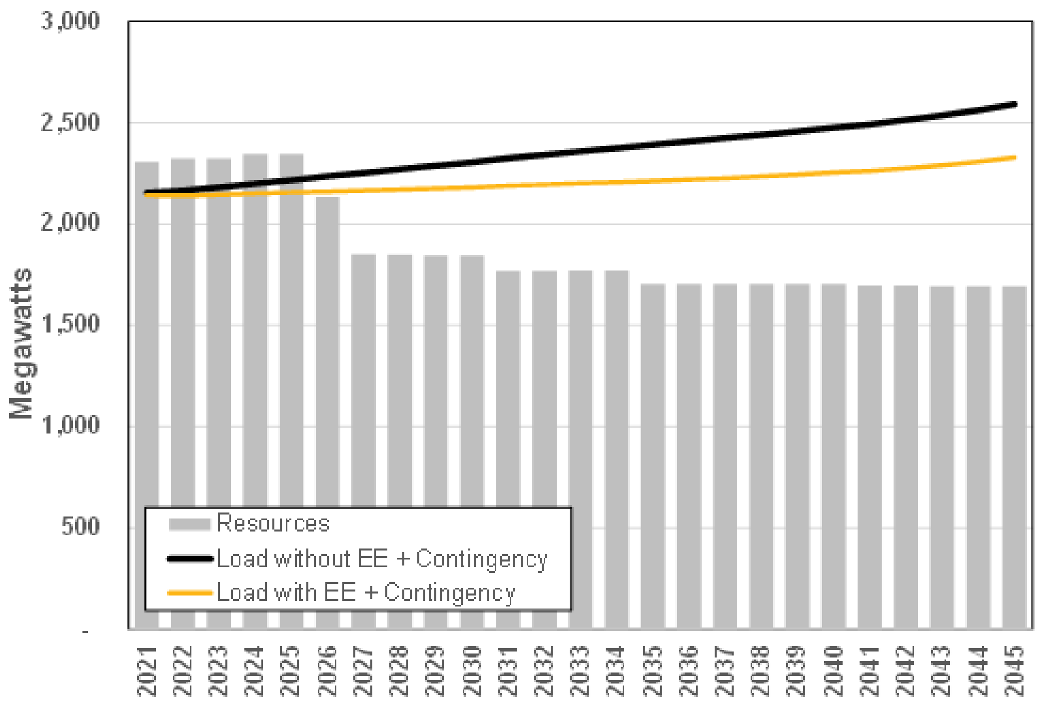
1. Executive Summary

The 2020 Electric Integrated Resource Plan (IRP) shapes Avista's resource strategy and planned procurements for the next 25 years. It provides a snapshot of existing resources and Avista's load forecast. The plan evaluates supply and demand-side resource options in multiple resource selection strategies over expected and possible future conditions to determine an optimal strategy to serve customers. The Preferred Resource Strategy (PRS) relies on modeling methods to balance cost, reliability, rate volatility, and environmental goals and mandates. Avista's management and Technical Advisory Committee (TAC) guide IRP development through their input and feedback on modeling and planning assumptions while providing the public with information on future energy requirements. TAC members include customers, Commission staff, consumer advocates, academics, environmental groups, utility peers, government agencies, independent power producers, and other interested parties.

Resource Needs

Under extreme cold, Avista expects its highest peak load in the winter. Avista's peak planning methodology considers operating reserves, regulation, load following, wind integration, and resource adequacy requirements. The Company has adequate resources and conservation programs to meet peak load requirements through December 2025. Figure 1.1 shows Avista's resource position through 2045. Chapter 7 – Long-Term Position details Avista's projected resource needs. Load growth and the loss of Colstrip[1], Lancaster, Northeast and the loss of hydro contracts drive Avista's resource deficits.

Figure 1.1: Load-Resource Balance—Winter Peak Load & Resource Availability



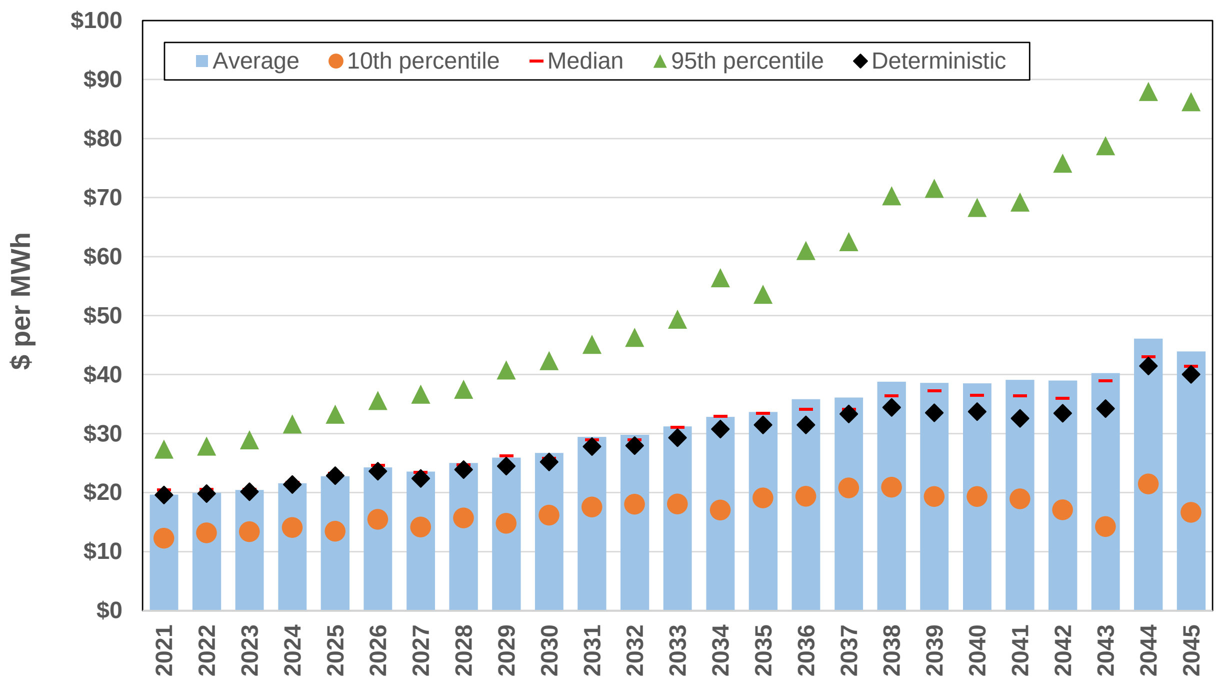
[1] This IRP assumes Colstrip no longer serves customers after 2025, although the owners have not made a decision on the future of the plant.

Modeling and Results

Avista uses a multistep process to develop its PRS, beginning with identifying and quantifying potential new resources to serve projected electricity demand across the Western Interconnect. This study determines the impact of external markets on the Northwest electricity marketplace. It then maps existing Avista resources to the transmission grid in a model simulating hourly operations for the Western Interconnect in the 2021 to 2045 IRP timeframe. The model adds new resources and transmission throughout the region as loads grow and resources retire. Monte Carlo-style analyses vary hydroelectric and wind generation, loads, forced outages and natural gas price data over 500 iterations of potential future market conditions to develop a forecast of wholesale Mid-Columbia electricity market prices through 2045.

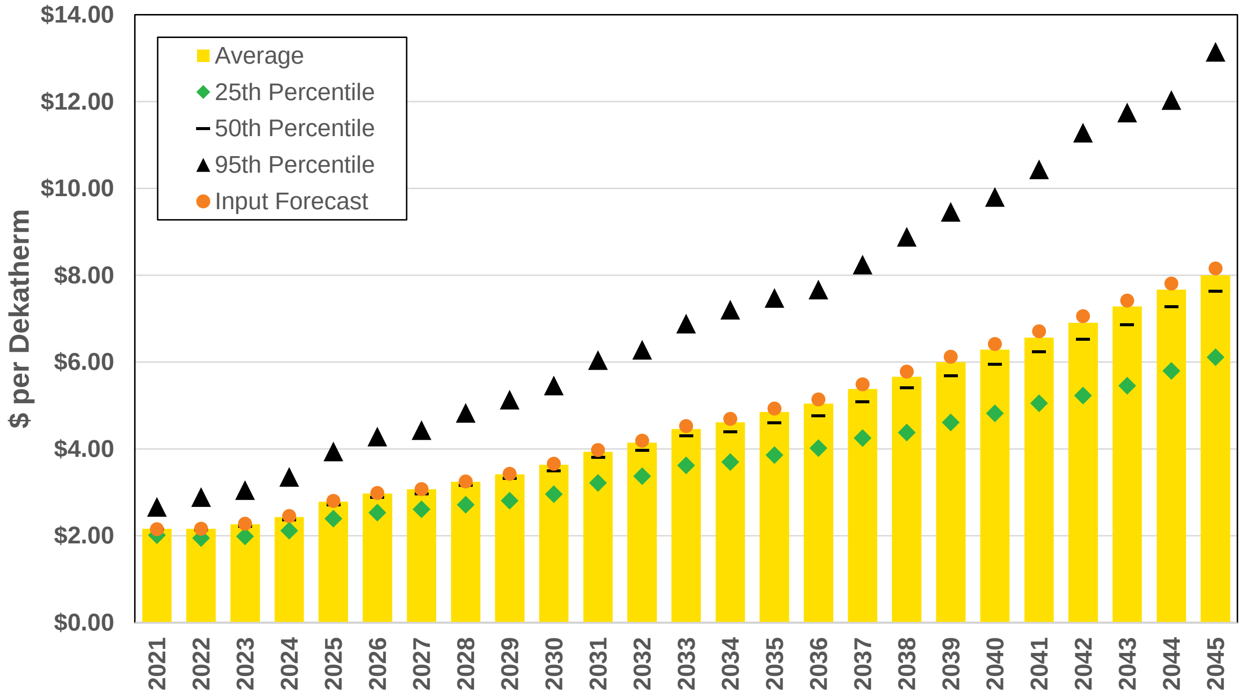
Figure 1.2 shows the 2020 IRP Mid-Columbia electricity price forecast for the Expected Case, including the range of prices from 500 Monte Carlo iterations. The levelized price is $27.86 per MWh in nominal dollars over the 2021-2045 timeframe.

Figure 1.2: Average Mid-Columbia Electricity Price Forecast



Electricity and natural gas prices are highly correlated because natural gas fuels marginal generation in the Northwest during most of the year. Figure 1.3 presents nominal Expected Case natural gas prices at the Stanfield trading hub, located in northeastern Oregon, as well as the forecast range from the 500 Monte Carlo iterations performed for the Expected Case. The average is $3.51 per dekatherm (Dth) over the next 25 years. See Chapter 10 – Market Analysis for natural gas and electricity price forecasts.

Figure 1.3: Stanfield Natural Gas Price Forecast

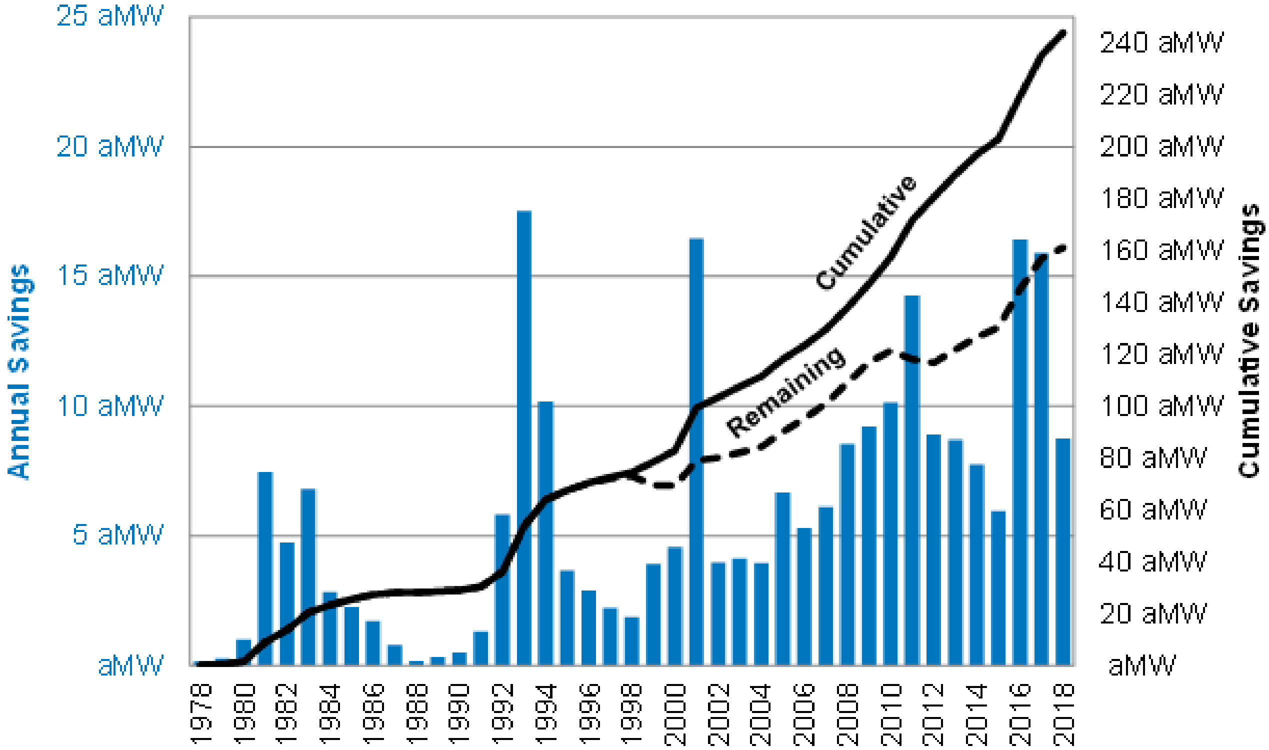


Energy Efficiency and Demand Response

Avista commissioned a Conservation Potential Assessment (CPA) and a Demand Response potential study to estimate potential applications in its service area. These studies evaluate over 6,000 potential energy efficiency programs and 17 Demand Response programs. Avista's commitment to energy efficiency is evident by loads that are 12.2 percent lower due to these efforts. Figure 1.4 illustrates the historical efficiency acquisitions as blue bars and the dashed line shows the amount of energy efficiency Avista estimates to remain on our system today.[2] Energy efficiency will serve 71 percent of future load growth. This is an increase from 53 percent in the prior IRP. See Chapter 5 – Energy Efficiency for more information. Going forward Demand Response programs will be an integral part of serving peak load using a variety of cost-effective programs and rate redesigns. See Chapter 6- Demand Response for more information.

[2] Cumulative savings are lower than the summation of annual program savings due to the estimated 18-year average measure life.

Figure 1.4: Annual and Cumulative Energy Efficiency Acquisitions



Preferred Resource Strategy

The PRS results from careful consideration and input by Avista's management, the TAC, and from the information gathered and analyzed in the IRP process. It meets future requirements with upgrades at existing generation facilities (thermal and hydroelectric), energy efficiency, energy storage, contracts, new renewable resources, and demand response, as shown in Table 1.1.

The 2020 PRS is a reasonable low-cost plan to meet both reliability and environmental requirements. Major changes from the 2017 IRP include the removal of new natural gas-fired peakers in exchange for long duration energy storage, additional demand response, 500 MW of new wind resources, and upgrades to thermal and hydroelectric facilities.

Each new supply-side resource and demand-side option is valued against the Mid-Columbia electricity market forecast to identify its future energy value, as well as its inherent risk measured by year-to-year portfolio power cost volatility. These values, and their associated capital and fixed operation and maintenance (O&M) costs, form the input into Avista's Preferred Resource Strategy Model (PRiSM). PRiSM assists Avista by developing optimal mixes of new resources. The resource plan may change depending on the final rulemaking and requirements of complying with the Clean Energy Transformation Act in Washington State and whether projects identified in the IRP are cost competitive and available at the time of need.

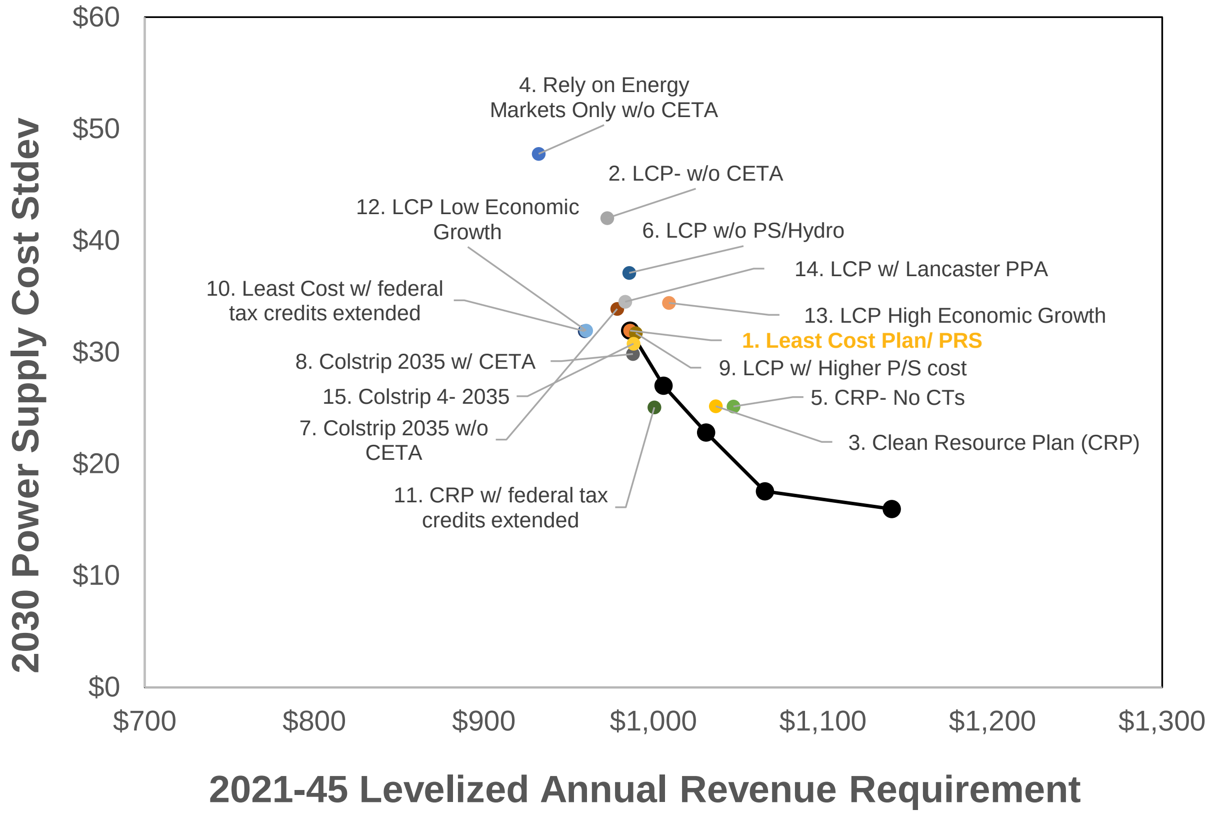
Table 1.1: The 2020 Preferred Resource Strategy

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2022-2023	200
Kettle Falls upgrade	2026	12
Colstrip 3 & 4 exits portfolio	2026	-222
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	175
Lancaster PPA expires	2026	-257
Post Falls upgrade	2027	8
Montana wind	2027	200
Mid-Columbia hydro	2031	75
Northeast CTs retires	2035	-55
Long Lake 2nd powerhouse	2035	68
Liquid-air storage (16 hours)	2036-2041	100
Wind (including PPA renewals)	2041-2043	300
Lithium-ion storage (4 hour)	2042-2045	300
Solar w/ storage (4 hours)	2044	55
4-hr Storage for Solar	2044	50
Supply-side resource net total (MW)		1,133
Supply-side additions through 2045 (MW)		1,667
Demand Response through 2045 (MW)		112
Energy Efficiency through 2045 (aMW)		187

The PRS provides a least reasonable-cost portfolio, minimizing future costs and risks within actual and expected environmental constraints. The Efficient Frontier illustrates the tradeoffs between risk and cost in an approach similar to finding an optimal mix of risk and return in an investment portfolio; as potential returns increase, so do risks. Conversely, reducing risk generally increases overall cost. Figure 1.5 presents the change in cost and risk from the many portfolio scenarios compared to the Efficient Frontier (black line). Lower power cost variability comes from investments in more expensive, but less risky, resources such as wind and hydroelectric upgrades. The PRS is the portfolio selected on the Efficient Frontier where reduced risk justifies the increased cost of the portfolio selection.

Chapter 12 – Portfolio Scenarios includes several scenarios identifying tipping points where the PRS could change under different conditions and alternate market futures. It also evaluates the impacts of varying load growth, resource capital costs, and greenhouse gas policies.

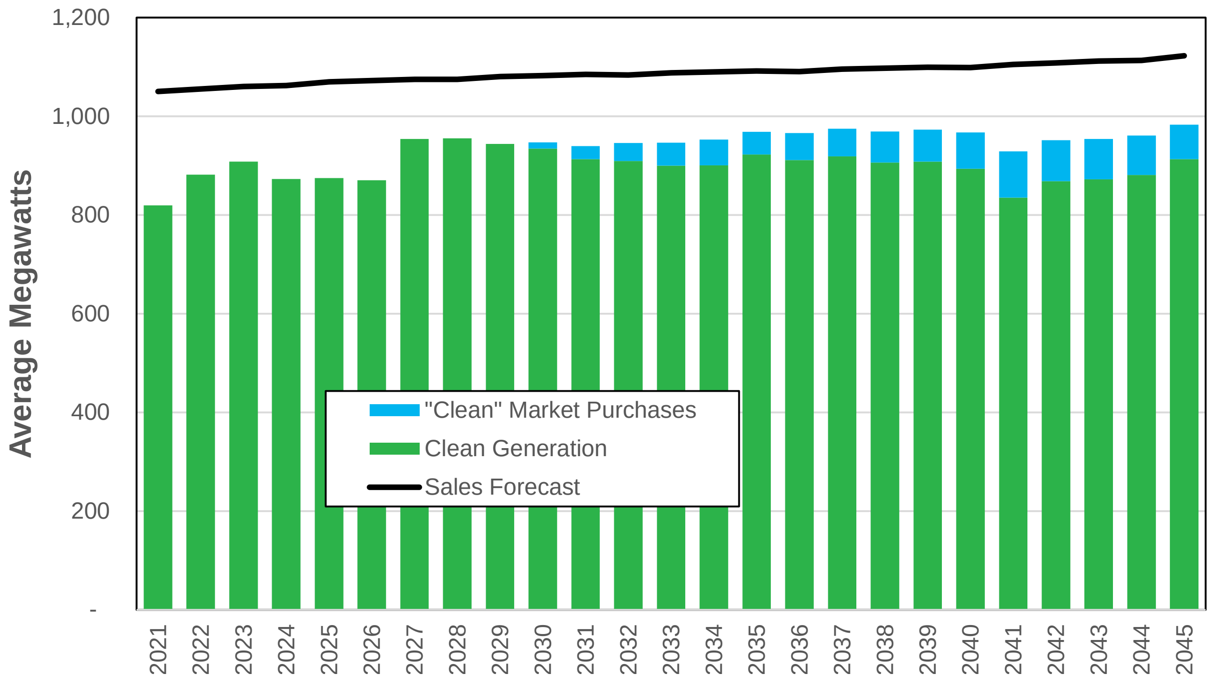
Figure 1.5: Portfolio Scenario Analysis



Clean Energy Goals

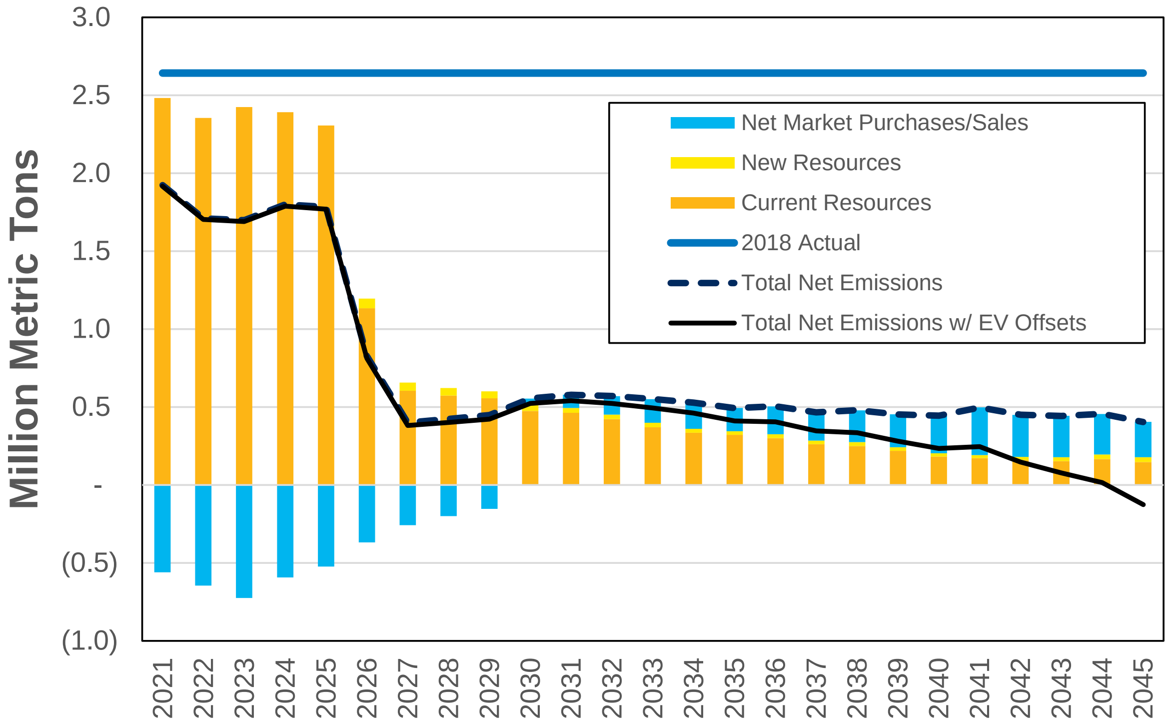
Acquiring an additional 500 MW (by 2027) of new wind resources along with upgrades to its hydroelectric and biomass facilities will position Avista to meet or exceed Washington's clean energy requirements. Energy storage will be key to removing carbon-emitting resources from our portfolio; our plans for combining long duration pumped hydro, liquid air energy storage (LAES) and lithium-ion technology provide the reliable capacity required to meet long cold winter periods where weather- and sun-dependent renewable resources do not always contribute to load service. The PRS meets nearly 89 percent of Avista's own clean energy goal to provide our customers with 100 percent net clean energy by 2027 at competitive prices. Figure 1.6 is the comparison between Avista's total energy sales (Idaho and Washington) and the annual average clean energy resources serving customers. Our plan complies with the goals of Washington's Energy Independence Act, relying on our Palouse Wind contract, generation from our Kettle Falls biomass facility, and upgrades to our Clark Fork and Spokane River hydroelectric developments.

Figure 1.6: Avista's Qualifying Renewables for Washington State's EIA



The shift to clean energy will reduce our greenhouse gas footprint significantly. Figure 1.7 shows Avista's emissions will decrease from 2018 levels by 79 percent in 2030 and 85 percent by 2045. When accounting for our contributions through incentives and programs to shift transportation fuel from petroleum to electricity, regional greenhouse gas reductions will be much greater than just from the removal of coal- and natural gas-fired generation shown below.

Figure 1.7: Avista Greenhouse Gas Emissions Forecast



Action Items

The 2020 Action Items chapter updates progress made on Action Items in the 2017 IRP and outlines activities Avista intends to perform between the publication of this report and publication of the next IRP. Items reflect input from staff at both of our state regulatory bodies, Avista's management team, and the TAC. Refer to Chapter 13 – Action Items for details about each of these categories.

2. Introduction and Stakeholder Involvement

Avista submits an Integrated Resource Plan (IRP) to the Idaho and Washington public utility commissions biennially.[1] Including its first plan in 1989, the 2020 IRP is Avista's sixteenth plan. It identifies and describes a Preferred Resource Strategy to meet load growth, resource deficits, and environmental mandates while balancing cost and risk measures.

Avista is statutorily obligated to provide safe and reliable electricity service to its customers at rates, terms, and conditions that are fair, just, reasonable, and sufficient. Avista assesses different resource acquisition strategies and business plans to acquire a mix of resources meeting resource adequacy requirements and optimizing the value of its current portfolio. The IRP is a resource evaluation tool, not a plan for acquiring a particular set of assets. Actual resource acquisition generally occurs through competitive bidding processes.

IRP Process

The IRP process originally began as the 2019 IRP with Avista's first Technical Advisory Committee (TAC) on July 25, 2018. In March 2019, Avista requested both Washington and Idaho to delay the IRP filing by six months, effectively creating the 2020 IRP cycle. The reason for the request was due to pending legislation in many states, including Washington, to change energy laws and regulations. Ultimately, Washington State passed the Clean Energy Transformation Act (CETA) while other states ended their legislative sessions without major changes. The Idaho Commission agreed with this change on April 16, 2019 in Order 34312 to change the IRP filing date to February 28, 2020. Washington also agreed with the change in filing dates but ultimately deferred this filing a second time in Order 2 of UE-180738 until 2021 because of CETA rulemaking requirements in the law.

The 2020 IRP is developed and written with the aid of a public process. Avista actively seeks input from a variety of constituents through its TAC meetings. The TAC is a mix of over 100 external participants, including staff from the Idaho and Washington commissions, customers, academics, environmental organizations, government agencies, consultants, utilities, and other interested parties who engage in the planning process. Avista distributed a draft of its work plan at the first of six TAC meetings for the 2020 IRP. Each TAC meeting covers different aspects of IRP planning activities. At the meetings, members provide contributions to, and assessments of, modeling assumptions, modeling processes, and results of Avista studies. Table 2.1 contains a list of TAC meeting dates and the agenda items covered in each meeting.

Appendix A and Avista's website[2] include the agendas, presentations, and meeting notes from the 2020 IRP TAC meetings. The website also contains IRPs and TAC meeting

[1] Washington IRP requirements are contained in WAC 480-100-238 Integrated Resource Planning. Idaho IRP requirements are in Case No. U-1500-165, Order No. 22299 and Case No. GNR-E-93-3, Order No. 25260.

[2] https://www.myavista.com/about-us/our-company/integrated-resource-planning

presentations back to 1989. The final work plan which, incorporates changes in the schedule, is included in Appendix B.

Table 2.1: TAC Meeting Dates and Agenda Items

Meeting Date	Agenda Items
TAC 1 – July 25, 2018	• TAC Meeting Expectations • 2017 IRP Commission Acknowledgements • Demand and Economic Forecast • Hydro One Merger Agreements • 2017 Acton Plan Updates • Draft 2019 Electric IRP Work Plan
TAC 2 – November 27, 2018	• Introduction & TAC 2 Recap • Modeling Process Overview • Generation Resource Options • Home Heating Technologies Overview • Resource Adequacy and Effective Load Carrying Capability (ELCC) • Electric IRP Key Assumptions • 2019 IRP Futures and Scenarios
TAC 3 – April 16, 2019	• Introduction & TAC 2 Recap • Regional Legislative Update • IRP Transmission Planning Studies • Distribution Planning within the IRP • Conservation Potential Assessment • Demand Response Potential Assessment • Pullman Smart Grid Demonstration Project Review • E3 Study- Resource Adequacy in the Pacific Northwest
TAC 4 – August 6, 2019	• Introduction & TAC 3 Recap • Washington SB 5116 and IRP Updates • Energy and Peak Load Forecast Update • Natural Gas Price Forecast • Electric Price Forecast • Existing Resource Overview • Final Resource Needs Assessment
TAC 5 – October 15, 2019	• Introduction & TAC 4 Recap • Energy Imbalance Market Update • Storage and Ancillary Service Analysis • Preliminary Preferred Resource Strategy • Preliminary Portfolio Scenario Results
TAC 6 – November 19, 2019	• Introduction & TAC 5 Recap • Review of Preferred Resource Strategy • Portfolio Scenario Results • 2020 IRP Action Items and Overview

Avista greatly appreciates the valuable contributions of its TAC members and wishes to acknowledge and thank the organizations that allow their attendance. Table 2.2 is a list of the organizations participating in the 2019/20 IRP TAC process.

Table 2.2: External Technical Advisory Committee Participating Organizations

Organization
350.Org Spokane
AEG
Biomethane, LLC
City of Spokane
Clearwater Paper
Climate Solutions
GE Energy
Idaho Conservation League
Idaho Department of Environmental Quality
Idaho Office of Energy and Mineral Resources
Idaho Public Utilities Commission
Inland Empire Paper
National Grid
NW Energy Coalition
Northwest Power and Conservation Council
Puget Sound Energy
Renewable Northwest
Residential and Small Commercial Customers
Sierra Club
Tyr Energy
Washington State Office of the Attorney General
Washington Department of Enterprise Services
Washington Utilities and Transportation Commission
Whitman County Commission

Future Public Involvement

Avista actively solicits input from interested parties to enhance its IRP process. We continue to expand TAC membership and diversity while maintaining the TAC meetings as an open public process.

2020 IRP Outline

The 2020 IRP consists of 13 chapters including the Executive Summary and this introduction. A series of technical appendices supplement this report.

Chapter 1: Executive Summary

This chapter summarizes the overall results and highlights of the 2020 IRP.

Chapter 2: Introduction and Stakeholder Involvement

This chapter introduces the IRP and details public participation and involvement in the IRP process.

Chapter 3: Economic and Load Forecast

This chapter covers regional economic conditions, Avista's energy and peak load forecasts, and load forecast scenarios.

Chapter 4: Existing Supply Resources

This chapter provides an overview of Avista-owned generating resources and its contractual resources and obligations and environmental regulations.

Chapter 5: Energy Efficiency

This chapter discusses Avista energy efficiency programs. It provides an overview of the conservation potential assessment and summarizes energy efficiency modeling results.

Chapter 6: Demand Response

This chapter discusses the demand response potential study and an overview of past demand response programs.

Chapter 7: Long-Term Position

This chapter reviews Avista reliability planning and reserve margins, resource requirements, and provides an assessment of its reserves and flexibility.

Chapter 8: Transmission & Distribution Planning

This chapter discusses Avista distribution and transmission systems, as well as regional transmission planning issues. It includes detail on transmission cost studies used in IRP modeling and summarizes of our 10-year Transmission Plan. The chapter concludes with a discussion of distribution efficiency and grid modernization projects; including storage benefits to the distribution system.

Chapter 9: Generation Resource Options

This chapter covers the costs and operating characteristics of supply side resource options modeled for the IRP.

Chapter 10: Market Analysis

This chapter details Avista IRP modeling and its analyses of the wholesale market.

Chapter 11: Preferred Resource Strategy

This chapter details the resource selection process used to develop the 2020 PRS and resulting avoided costs.

Chapter 12: Portfolio Scenarios

This chapter presents alternative resource portfolios and shows how each scenario performs under different energy market conditions.

Chapter 13: Action Items

This chapter discusses progress made on Action Items contained in the 2017 IRP. It details the action items Avista will focus on between publication of this plan and the 2021 IRP(s).

Idaho Regulatory Requirements

The IRP process for Idaho has several requirements documented in IPUC Orders Nos. 22299 and 25260. Order 22299 dates back to 1989; this order outlines the requirement for the utility to file a "Resource Management Report". This report *recognize[s] the managerial aspects of owning and maintaining existing resources as well as procuring new resources and avoiding/reducing load*. *[The Commission's] desire is the report on the utility's planning status, not a requirement to implement new planning efforts according to some bureaucratic dictum*. *We realize that integrated resource planning is an ongoing, changing process. Thus, we consider the RMR required herein to be similar to an accounting balance sheet, i.e., a "freeze-frame" look at a utility's fluid process.*

The report should discuss any flexibilities and analysis considered during comprehensive resource planning such as:

1. Examination of load forecast uncertainties
2. Effects of known or potential changes to existing resources
3. Consideration of demand and supply side resource options
4. Contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead-time, reliability, risk, etc.) as future events unfold.

Avista outlines the order's requirements below for ease of readability for each of the Commission's requirements.

Existing Resource Stack

Identification of all resources by category below[3]; including the utility shall provide a copy of the utility's most recent U.S. Department of Energy Form EIA-714 submittal and the following specific data, as defined by the NERC, ought to be included as an appendix[4]:

a) Hydroelectric;
   i. Rated capacity by unit;
   ii. Equivalent Availability Factor by month for most recent 5 years;
   iii. Equivalent Forced Outage Rate by month for most recent 5 years; and
   iv. FERC license expiration date.
b) Coal-fired;
   i. Rated Capacity by unit;
   ii. Date first put into service;
   iii. Design plant life (including life extending upgrades, if any);
   iv. Equivalent Availability Factor by month for most recent 5 years; and
   v. Equivalent Forced Outage Rate by month for most recent 5 years.
c) Oil or Gas fired;
   i. Rated Capacity by unit;
   ii. Date first put into service;
   iii. Design plant life (including life extending upgrades, if any);
   iv. Equivalent Availability Factor by month for most recent 5 years; and
   v. Equivalent Forced Outage Rate by month for most recent 5 years.
d) PURPA Hydroelectric;
   i. Contractual rated capacity;
   ii. Five-year historic hours connected to system, by month (if known);
   iii. Five-year historic generation (kWh), by month;
   iv. Level of dispatchability, if any; and
   v. Contract expiration date.
e) PURPA Thermal;
   i. Contractual rated capacity;
   ii. Five-year historic hours connected to system, by month (if known);
   iii. Five-year historic generation (kWh), by month;
   iv. Level of dispatchability, if any; and
   v. Contract expiration date.
f) Economy Exchanges;
   I. For contract purchases & exchanges, key contract terms and conditions relating to capacity, energy, availability, price, and longevity.
   II. For economy purchases and exchanges, 5-year historical monthly average capacity, energy, and prices.
g) Economy Purchases;
   I. For contract purchases & exchanges, key contract terms and conditions relating to capacity, energy, availability, price, and longevity.
   II. For economy purchases and exchanges, 5-year historical monthly average capacity, energy, and prices.
h) Contract Purchases;

[3] Resources less than three megawatts should be grouped as a single resource in the appropriate category.
[4] FERC Form 714 can be on-line at https://www.ferc.gov/docs-filing/forms/form-714/data.asp

I. For contract purchases & exchanges, key contract terms and conditions relating to capacity, energy, availability, price, and longevity.
II. For economy purchases and exchanges, 5-year historical monthly average capacity, energy, and prices.

i) Transmission Resources; and
  I. Information useful for estimating the power supply benefits and limitations appurtenant to the resources in question.

j) Other.
  I. Information useful for estimating the power supply benefits and limitations appurtenant to the resources in question.

Load Forecast

Each RMR should discuss expected 20-year load growth scenarios for retail markets and for the federal wholesale market including "requirements" customers, firm sales, and economy (spot) sales. For each appropriate market, the discussion should:

a) identify the most recent monthly peak demand and average energy consumption (where appropriate by customer class), both firm and interruptible;
b) identify the most probable average annual demand and energy growth rates by month and, where appropriate, by customer class over at least the next three years and discuss the years following in more general terms;
c) discuss the level of uncertainty in the forecast, including identification of the maximum credible deviations from the expected average growth rates; and
d) identify assumptions, methodologies, data bases, models, reports, etc. used to reach load forecast conclusions.

This section of the report is to be a short synopsis of the utility's present load condition, expectations, and level of confidence. Supporting information does not need to be included but should be cited and made available upon request.

Additional Resource Menu

This section should consist of the utility's plan for meeting all potential jurisdictional load over the 20-year planning period. The discussion should include references to expected costs, reliability, and risks inherent in the range of credible future scenarios.

- An ideal way to handle this section could be to describe the most probable 20-year scenario followed by comparative descriptions of scenarios showing potential variations in expected load and supply conditions, and the utility's expected responses thereto. Enough scenarios should be presented to give a clear understanding of the utility's expected responses over the full range of possible future conditions.
- The guidance provided above is intended to insure maximum flexibility to utilities in presenting their resource plans. Ideally, each utility will use several scenarios to demonstrate potential maximum, minimum, and intermediate levels of new resource requirements and the expected means of fulfilling those requirements. For example,
  - a credible scenario requiring maximum new resources might be regional load growth exceeding 3% per year combined with catastrophic destruction (earthquake, fire, flood, etc.) of a utility's largest resource (i.e., Bridger coal

plant for IPCo and PP&L, Hunter coal plant for UP&L, and Noxon hydro plant for WWP).

- A credible scenario causing reduced utilization of existing resources might be regional stagflation combined with loss of a major industry within a utility's service territory. Analyses of intermediate scenarios would also be useful.

- To demonstrate the risks associated with various proposed responses, certain types of information should be supplied to describe each method of meeting load. For example,
  - if new hydroelectric generating plants are proposed, the lead time required to receive FERC licensing and the risk of license denial should be discussed.
  - If new thermal generating plants are proposed, the size, potential for unused capacity, risks of cost escalation, and fuel security should be discussed and compared to other types of plants.
  - If off-system purchases are proposed, specific supply sources should be identified, regional resource reserve margin should be discussed with supporting documentation identified, potential transmission constraints and/or additions should be discussed, and all associated costs should be estimated.
  - If conservation or demand side resources are proposed, they should be identified by customer class and measure, including documentation of availability, potential market penetration and cost.
- Because existing hydroelectric plants could be lost to competing companies if FERC relicensing requirements are not aggressively pursued, relicensing alternatives require special consideration. For example,
  - if hydroelectric plant relicensing upgrades are proposed, their costs should be presented both as a function of increased plant output and of total plant output to recognize the potential of losing the entire site.
  - Costs of upgrades not required for relicensing should be so identified and compared only to actual increased capacity/energy availability at the unit, line, substation, distribution system, or other affected plant. Increased maintenance costs, instrumentation, monitoring, diagnostics, and capital investments to improve or maintain availability should be quantified.
- Because PURPA projects are not under the utility's control, they also require special consideration. Each utility must choose its own way of estimating future PURPA supplies. The basis for estimates of PURPA generation should be clearly described.

Other provisions from Order 22299

- Because the RMR is expected to be a report of a utility's plans, and because utilities are being given broad discretion in choosing their reporting format, Least Cost Plans or Integrated Resource Plans submitted to other jurisdictions should…. be applicable in Idaho
  - Utilities should use discretion and judgement to determine if reports submitted to other jurisdictions provide such emphasis, if adding an

appendix would supply such emphasis, or if a separate report should be prepared for Idaho.
    - o The project manager responsible for the content and quality of the RMR shall be clearly identified therein and a resume of her/his qualifications shall be included as an appendix to the RMR.
- Finally, the Resource Management Report is not designed to turn the IPUC into a planning agency nor shall the Report constitute pre-approval of a utility's proposed resource acquisitions.
- The reporting process is intended to be ongoing-revisions and adjustments are expected. The utilities should work with the Commission Staff when reviewing and updating the RMRs. When appropriate, regular public workshops could be helpful and should be a part of the reviewing and updating process.
- Most parties seem to agree that reducing and/or avoiding peak capacity load or annual energy load has at least the equivalent effect on system reliability of adding generating resources of the same size and reliability. Furthermore, because conservation almost always reduces transmission and distribution system loads, most parties consider reliability effects of conservation superior to those of generating resources. Consequently, the Commission finds that electric utilities under its jurisdiction, when formulating resource plans, should give consideration to appropriate conservation and demand management measures equivalent to the consideration given generating resources.
- Therefore, we find that the parties should use the avoided cost methodology resulting from the No. U-1500-170 case for evaluating the cost effectiveness of conservation measures. The specific means for comparing No. U-1500-170 case avoided costs to conservation costs will initially be developed case-by-case as specific conservation programs are proposed by each utility. Prices to be paid for conservation resources procured by utilities are discussed later in this Order.
- Give balanced consideration to demand side and supply side resources when formulating resource plans and when procuring resources.
- Submit to the Commission, no later than March 15, 1989, and at least biennially thereafter, a Resource Management Report describing the status of its resource planning as of the most current practicable date.

Order 25260 Requirements

This order documents additional requirements for resource planning including:

- Give full consideration to renewables, among other resource options.
- Investigate and carefully weigh the site-specific potential for particular renewables in their service area.
- Deviations from the integrated resource plans must be explained. The appropriate place to determine the prudence of an electric utility's plan or the prudence of an electric utility's following or failing to follow a plan will be in general rate case or other proceeding in which the issue is noticed.

2017 IRP Discussion and Findings

Text is from IPUC Order 33971, Case No. AVU-E-17-08

In doing so, we reiterate that an IRP is a working document that incorporates many assumptions and projections at a specific point in time. It is a plan, not a blueprint, and by issuing this Order we merely acknowledge the Company's ongoing planning process, not the conclusions or results reached through that process. With this Order, the Commission is not approving the IRP or any resource acquisitions referenced in it, endorsing any particular element in it, or opining on the Company's prudence in selecting the IRP's preferred resource portfolio. The appropriate place to determine the prudence of the IRP or the Company's decision to follow or not follow it, and the validation of predicted performance under the IRP, will be a general rate case or another proceeding in which the issue's noticed.

The Commission appreciates the active participation in the IRP process of the Staff, ICL, and other stakeholders and customers, and we are confident that their input helps the Company develop a better and more comprehensive IRP. We note that customers and Staff commented on alternatives regarding the closure of Colstrip and the inclusion in the PRS of a new gas peaker plant after the expiration of the Lancaster agreement. We encourage the Company to continue evaluating all options regarding these resources, and to consider the best interests of its customers when developing the 2019 IRP. The Commission appreciates the Company's collaboration with stakeholders in developing the 2017 Electric IRP.

Washington Regulatory Requirements

Avista typically files its Electric IRP in both Washington and Idaho. The Washington Commission ruled in Order 2 from Docket UE-180738 Avista to be compliant with the IRP rules when it filed a Progress Report on October 25, 2019. This ruling was in partly due to passage of the Clean Energy Transformation Act (CETA) where the Commission needs to complete certain rulemaking prior to acknowledging any plans under their jurisdiction. CETA requires new rules for IRPs because of new requirements and new reports; including the development of the Clean Energy Action Plan (CEAP) and the Clean Energy Implementation Plan (CEIP). This rule making process must finish prior to December 31, 2020. Some of the new requirements Avista must consider include accounting for the social cost of carbon, removal of coal from Washington retail rates after 2025, transformation to 100 percent clean energy, distribution and transmission planning within the IRP, accounting for economic, health, and environmental burdens and benefits.

Avista's intention in this IRP is to model a future IRP/CEAP taking into account potential rules as described in CETA to meet resource plan requirements for a least reasonable cost reliable system. This IRP will not be an official filing in Washington for acknowledgement, but Avista will filed it as an advisory report of Avista's ongoing resource planning efforts. Avista anticipates this plan will change because of final rulemaking, but this IRP provides the Company and stakeholders a practical plan addressing new requirements and potential techniques to solve those new requirements.

Summary of 2020 IRP Changes from the 2017 IRP

This summary provides an overview of major changes in the analysis since the 2017 IRP. This section does not describe the specific changes, but rather it briefs readers regarding significant or major methodological changes.

Capacity and Energy Position, Including Load Forecasting

- This IRP uses a 5 percent LOLP for the PRS rather than the 2017 IRP's 14 percent winter planning margin and 7 percent summer planning margin. This change resulted in an 18 percent planning margin for the PRS.
- Load forecast includes adjustments for natural gas penetration.
- Assumes Colstrip exits the portfolio in 2025, and then studies the cost impacts of extending the project to 2035.
- Assumes the Northeast CT retires in 2035.

Energy Efficiency and Demand Response

- Idaho energy efficiency analysis uses the Utility Cost Test (UCT) for programs selection rather than the Total Resource Cost (TRC) test.
- Washington energy efficiency analysis includes savings from associated greenhouse gas emissions priced at the social cost of carbon using the 2.5 percent discount rate proscribed in CETA. The savings assumes the average emissions from the regional power system on an annual basis.
- This IRP uses a full demand response (DR) potential assessment for potential DR programs for both residential and commercial/industrial customers. The previous DR potential study only focused on commercial and industrial customers with a description of potential residential programs.

Supply-Side Resource Options

- Avista modelled several energy storage options in this IRP including pumped hydro storage, lithium-ion, vanadium flow, zinc bromide flow, liquid air, and hydrogen all with varying energy durations. The previous IRP modeled storage generically.
- This IRP models wind, solar, pumped hydro storage, nuclear, and geothermal as purchase power agreements; whereas the previous IRPs assumed these resources were in Avista's rate base (i.e. owned by Avista).
- Avista assigned peak credits to renewable and storage resources depending on their ability to meet peak loads using its ARAM model.
- This IRP includes the cost of upstream greenhouse gas emissions from the natural gas-fired projects at the social cost of carbon for Washington's share of resources.
- The IRP analysis uses a regional emissions factor for market purchases and sales to adjust greenhouse emissions reporting for the PRS.

Market Analysis

- Avista utilizes Energy Exemplar's (Aurora) database for most inputs into the price forecast with the exception of Avista's proprietary utility specific information, natural gas price forecast from two consultants, and regional hydro conditions.

- The Aurora capacity expansion study is required to meet the qualifications of state clean energy policies including CETA. The model must also meet a 5 percent LOLP threshold for reliability when selecting new resources.
- A cap and trade greenhouse gas emissions cap applies in modeling Oregon.
- This IRP used two consultant forecasts along with market forward prices for the natural gas price forecast. The previous IRP used only one consultant forecast along with forward prices.

Portfolio Optimization Analysis

- The 2020 IRP optimizes a resource portfolio for 25 years instead of 20 years. Moving to 25 years led to removing some of the cost estimates for resource beyond 20 years.
- Includes social cost of carbon costs for Washington's share of resource emissions and market purchases for new resource acquisitions, DR programs, and energy efficiency. The social cost of carbon is not included in the projected dispatch decision of resources in the Expected Case, but is included in the optimization of resource decisions.
- Models the clean energy requirements of CETA in Washington State.
- Includes total customer rate estimates as compared to previous IRP's showing only power supply costs.

3. Economic & Load Forecast

An explanation and quantification of Avista's loads and resources are integral to the IRP. This chapter summarizes customer and load projections, load growth scenarios, and recent enhancements to forecasting models and processes.

Chapter Highlights

- The 2020 energy forecast grows 0.3 percent per year, replacing the 0.5 percent annual growth rate in the 2017 IRP.
- Peak load growth is 0.3 percent in the winter and 0.4 percent in the summer.
- Retail sales and residential use per customer forecasts continue to decline from 2017 IRP projections.

Economic Characteristics of Avista's Service Territory

Avista's core electric service area includes more than a half million people residing in Eastern Washington and Northern Idaho. Three metropolitan statistical areas (MSAs) dominate its service area: the Spokane-Spokane Valley, WA MSA (Spokane-Stevens counties); the Coeur d'Alene, ID MSA (Kootenai County); and the Lewiston-Clarkson ID-WA, MSA (Nez Perce-Asotin counties). These three MSAs account for just over 70 percent of both Avista's customers (i.e., meters) and load. The remaining 30 percent are in low-density rural areas in both states. Washington accounts for about two-thirds of customers and Idaho the remaining one-third.

Population

Population growth is increasingly a function of net migration within Avista's service area. Net migration is strongly associated with both service area and national employment growth through the business cycle. The regional business cycle follows the U.S. business cycle, meaning regional economic expansions or contractions follow national trends.[1] Econometric analysis shows that when regional employment growth is stronger than U.S. growth over the business cycle, it is associated with increased in-migration. The reverse holds true. Figure 3.1 shows annual population growth since 1971 and highlights the recessions. During all deep economic downturns since the mid-1970s, reduced population growth rates in Avista's service territory led to lower load growth.[2] The Great Recession reduced population growth from nearly 2 percent in 2007 to less than 1 percent from 2010 to 2013. Accelerating service area employment growth in 2013 helped push population growth to around 1 percent starting in 2014.

[1] *An Exploration of Similarities between National and Regional Economic Activity in the Inland Northwest*, Monograph No. 11, May 2006. http://www.ewu.edu/cbpa/centers-and-institutes/ippea/monograph-series.xml.
[2] Data Source: Bureau of Economic Development, U.S. Census, and National Bureau of Economic Research.

Figure 3.1: MSA Population Growth and U.S. Recessions, 1971-2019

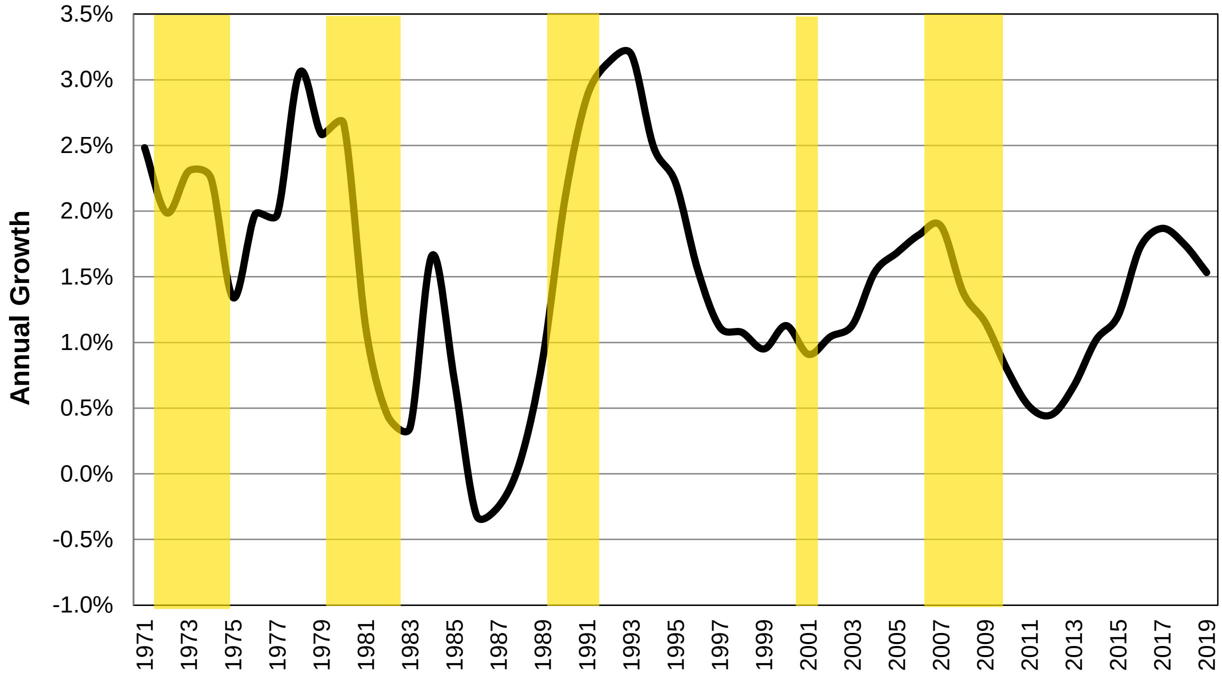


Figure 3.2 shows population growth since the start of the Great Recession in 2007.[3] Service area population growth over the 2010-2012 period was weaker than the U.S.; it was closely associated with the strength of regional employment growth relative to the U.S. over the same period. The same can be said for the increase in service area population growth in 2014 relative to the U.S. The association of employment growth to population growth has a one-year lag. The relative strength of service area population growth in year "y" is positively associated with service area population growth in year "y+1". Econometric estimates using historical data show holding the U.S. employment-growth constant, every 1 percent increase in service area employment growth is associated with a 0.4 percent increase in population growth in the next year.

Employment

It is useful to examine the distribution of employment and employment performance since 2007 given the correlation between population and employment growth. The Inland Northwest is now a services-based economy rather than its former natural resources-based manufacturing economy. Figure 3.3 shows the breakdown of non-farm employment for all three service area MSAs.[4] Approximately 70 percent of employment in the three MSAs is in private services, followed by government (17 percent) and private goods-producing sectors (14 percent). Farming accounts for 1 percent of total employment.

Spokane and Coeur d'Alene MSAs are major providers of health and higher education services to the Inland Northwest.

[3] Data Source: Bureau of Economic Analysis, U.S. Census, and Washington State OFM.
[4] Data Source: Bureau of Labor and Statistics.

Figure 3.2: Avista and U.S. MSA Population Growth, 2007-2019

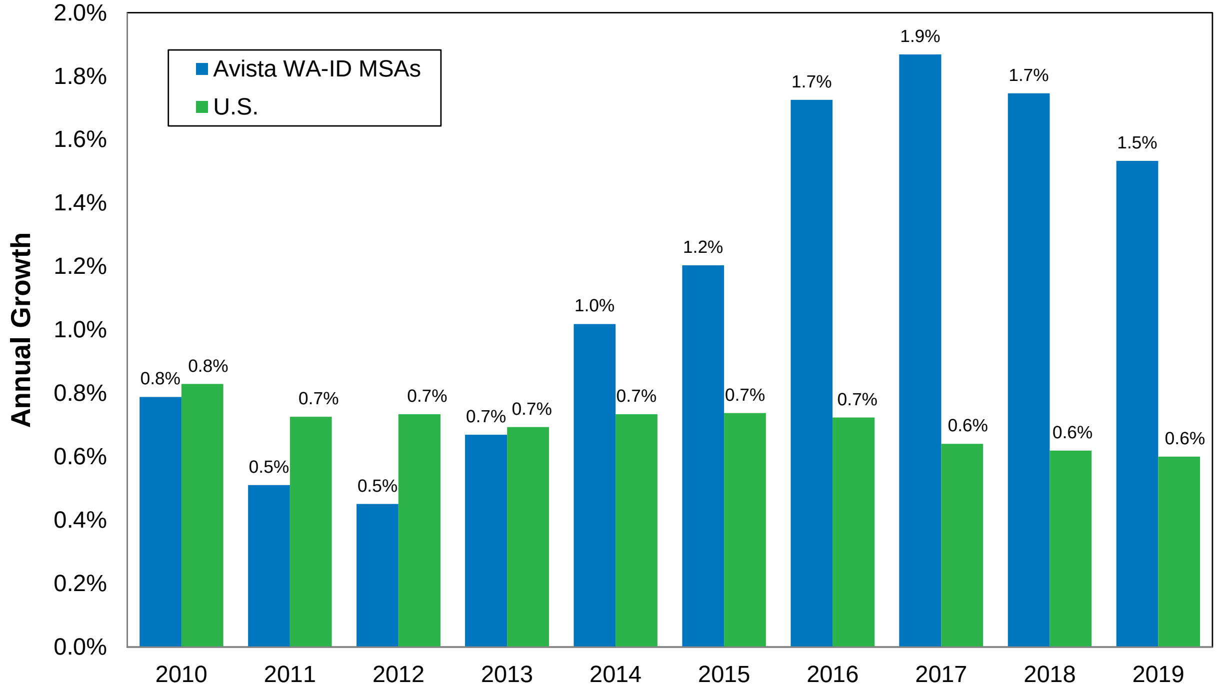
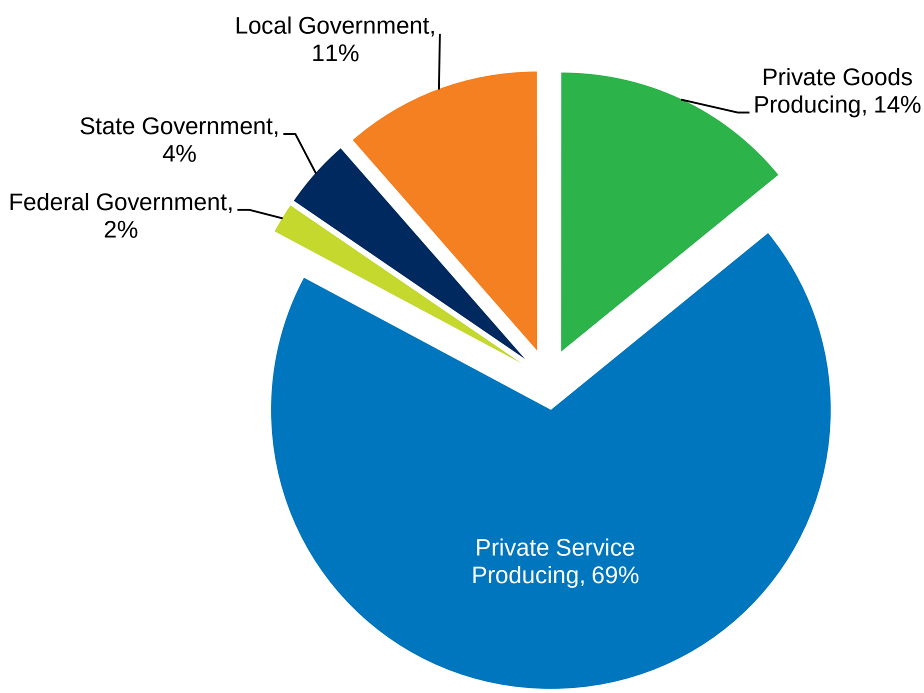


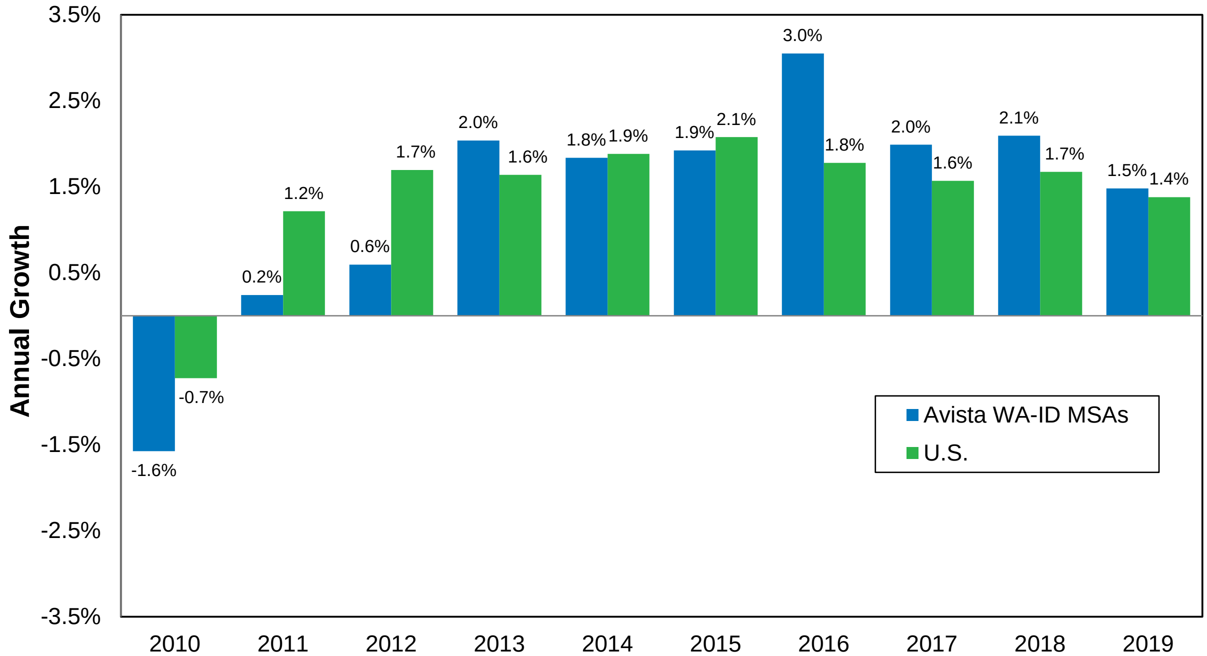
Figure 3.3: MSA Non-Farm Employment Breakdown by Major Sector, 2018



Non-farm employment growth averaged 2.7 percent per year between 1990 and 2007. However, Figure 3.4 shows that service area employment lagged the U.S. recovery from the Great Recession for the 2010-2012 period.[5] Regional employment recovery did not materialize until 2013, when services employment started to grow. Prior to this, reductions in federal, state, and local government employment offset gains in goods producing sectors. Service area employment growth began to match or exceed U.S. growth rates by the fourth quarter 2014.

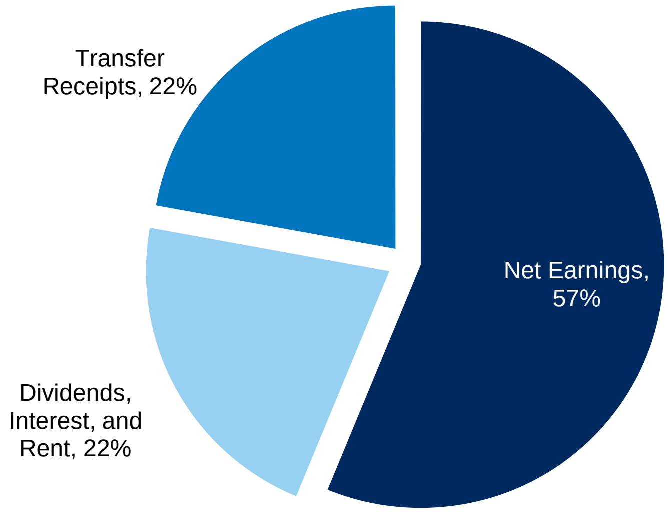
Figure 3.5 shows the distribution of personal income, a broad measure of both earned income and transfer payments, for Avista's Washington and Idaho MSAs.[6] Regular income includes net earnings from employment, and investment income in the form of dividends, interest and rent. Personal current transfer payments include money income and in-kind transfers received through unemployment benefits, low-income food assistance, Social Security, Medicare, and Medicaid.

Figure 3.4: Avista and U.S. MSA Non-Farm Employment Growth, 2010-2019



[5] Data Source: Bureau of Labor and Statistics.
[6] Data Source: Bureau of Economic Analysis.

Figure 3.5: MSA Personal Income Breakdown by Major Source, 2018

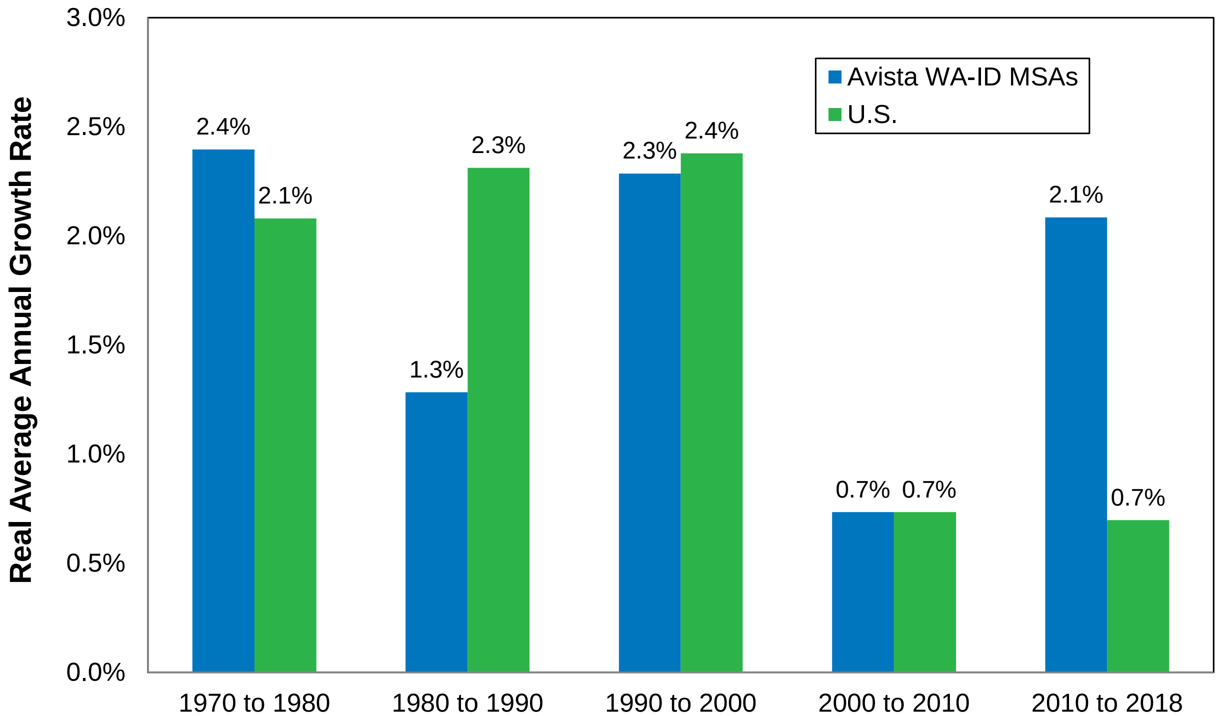


Transfer payments in Avista's service area in 1970 accounted for 12 percent of the local economy. The income share of transfer payments has nearly doubled over the last 40 years to 22 percent. The relatively high regional dependence on government employment and transfer payments means transfer program reform may reduce future growth. Although 57 percent of personal income is from net earnings, transfer payments account for more than one in every five dollars of personal income. Recent years have seen transfer payments become the fastest growing component of regional personal income. This growth reflects an aging regional population, a surge of military veterans, and the Great Recession; the later significantly increased payments from unemployment insurance and other low-income assistance programs.

Figure 3.6 shows the real (inflation adjusted) average annual growth per capita income by MSA for Avista's service area and the U.S. overall. Note that in the 1980 – 1990 period the service area experienced significantly lower income growth compared to the U.S. because of the back-to-back recessions of the early 1980s.[7] The impacts of these recessions were more negative in the service area compared to the U.S. as a whole, so the ratio of service area per capita income to U.S. per capita income fell from 93 percent in the 1970s to around 85 percent by the mid-1990s. The income ratio has not since recovered.

[7] Data Source: Bureau of Economic Analysis.

Figure 3.6: Avista and U.S. MSA Real Personal Income Growth, 1970-2018



Five-Year Load Forecast Methodology

In non-IRP years, the retail and native load forecasts have a five-year time horizon. Avista conducts the forecasts each spring and fall. The results feed into Avista's revenue model, which converts the load forecast into a revenue forecast. In turn, the revenue forecast feeds Avista's earnings model. In IRP years, the long-term forecast bootstraps off the five-year forecast by applying growth assumptions beyond year five.

Overview of the Five-Year Retail Load Forecast

The five-year retail load forecast is a two-step process. For most schedules in each class, there is a monthly use per customer (UPC) forecast and a monthly customer forecast.[8] The load forecast results from multiplying the customer and UPC forecasts. The UPC and customer forecasts are generated using time-series econometrics, as shown in Equation 3.1.

[8] For schedules representing a single customer, where there is no customer count and for street lighting, Avista forecast total load directly without first forecasting UPC.

Equation 3.1: Generating Schedule Total Load

$$F(kWh_{t,y_c+j,s}) = F(kWh/C_{t,y_c+j,s}) \times F(C_{t,y_c+j,s})$$

Where:

- $F(kWh_{t,y_c+j,s})$ = the forecast for month t, year j = 1,…,5 beyond the current year, y_c ,for schedule s.
- $F(kWh/C_{t,y_c+j,s})$ = the UPC forecast.
- $F(C_{t,y_c+j,s})$ = the customer forecast.

UPC Forecast Methodology

The econometric modeling for UPC is a variation of the "fully integrated" approach expressed by Faruqui (2000) in the following equation:[9]

Equation 3.2: Use Per Customer Regression Equation

$$kWh/C_{t,y,s} = \alpha W_{t,y} + \beta Z_{t,y} + \epsilon_{t,y}$$

The model uses actual historical weather, UPC, and non-weather drivers to estimate the regression in Equation 3.2. To develop the forecast, normal weather replaces actual weather (W) along with the forecasted values for the Z variables (Faruqui, pp. 6-7). Here, W is a vector of heating degree day (HDD) and cooling degree day (CDD) variables; Z is a vector of non-weather variables; and $\varepsilon_{t,y}$ is an uncorrelated N(0,σ) error term. For non-weather sensitive schedules, W = 0.

The W variables will be HDDs and CDDs. Depending on the schedule, the Z variables may include real average energy price (RAP); the U.S. Federal Reserve industrial production index (IP); residential natural gas penetration (GAS); non-weather seasonal dummy variables (SD); trend functions (T); and dummy variables for outliers (OL) and periods of structural change (SC). RAP is measured as the average annual price (schedule total revenue divided by schedule total usage) divided by the consumer price index (CPI), less energy. For most schedules, the only non-weather variables are SD, SC, and OL. See Table 3.1 for the occurrence RAP and IP.

If the error term appears to be non-white noise, then the forecasting performance of Equation 3.2 can be improved by converting it into an ARIMA "transfer function" model such that $\epsilon_{t,y}$ = ARIMA$\epsilon_{t,y}(p,d,q)(p_k,d_k,q_k)_k$. The term p is the autoregressive (AR) order, d is the differencing order, and q is the moving average (MA) order. The term p_k is the order of seasonal AR terms, d_k is the order of seasonal differencing, and q_k is the seasonal order of MA terms. The seasonal values relate to "k," or the frequency of the data. With the current monthly data set, k = 12.

Certain schedules, such as those related to lighting, use simpler regression and smoothing methods because they offer the best fit for irregular usage without seasonal or weather related behavior, is in a long-run steady decline, or is seasonal and unrelated to weather.

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[9] Faruqui, Ahmad (2000). *Making Forecasts and Weather Normalization Work Together*, Electric Power Research Institute, Publication No. 1000546, Tech Review, March 2000.

Avista defines normal weather for the forecast as a 20-year moving average of degree-days taken from the National Oceanic and Atmospheric Administration's Spokane International Airport data. Normal weather updates only when a full year of new data is available. For example, normal weather for 2018 is the 20-year average of degree-days for the 1998 to 2017 period; and 2019 is the 1999 to 2018 period.

The choice of a 20-year moving average for defining normal weather reflects several factors. First, recent climate research from the National Aeronautics and Space Administration's (NASA) Goddard Institute for Space Studies (GISS) shows a shift in temperature starting about 20 years ago. The GISS research finds the summer temperatures in the Northern Hemisphere increased one degree Fahrenheit above the 1951-1980 reference period; the increase started roughly 20 years ago in the 1981-1991 period.[10] An in-house analysis of temperature in Avista's Spokane-Kootenai service area, using the same 1951-1980 reference period, also shows an upward shift in temperature starting about 20-years ago. A detailed discussion of this analysis is in the peak-load forecast section of this chapter.

The second factor in using a 20-year moving average is the volatility of the moving average as a function of the years used to calculate the average. Moving averages of 10 and 15 years showed considerably more year-to-year volatility than the 20-year average. This volatility can obscure longer-term trends and lead to overly sharp changes in forecasted loads when applying the updated definition of normal weather each year. These sharp changes would also cause excessive volatility in the revenue and earnings forecasts.

As noted earlier, if non-weather drivers appear in Equation 3.2, then they must also be in the forecast for five years to generate the UPC forecast. The assumption in the five-year forecast for this IRP is for RAP to be constant out to 2025; increase at 1% from 2026 to 2029; and then increase 1.5% until 2045. RAP no longer appears explicitly in the regression equations for the five-year forecast. The coefficient estimates for RAP have become unstable and statistically insignificant. Therefore, the 2020 IRP assumes elasticity to be -0.3%, based on long-run estimates from academic literature.[11]

This IRP generates IP forecasts from a regression using the GDP growth forecasts (GGDP). Figure 3.7 describes this process.

[10] See Hansen, J.; M. Sato; and R. Ruedy (2013). *Global Temperature Update Through 2012*, http://www.nasa.gov/topics/earth/features/2012-temps.html.

[11] Avista is unable to produce reliable elasticity estimates using its own UPC data. It is often difficult to obtain reliable elasticity estimates using data for an individual utility. Therefore, the Company has opted to rely on academic estimates using regionalized data covering multiple utilities. As theory would predict, the literature indicates that short-term elasticity is lower than long-term elasticity.

Table 3.1: UPC Models Using Non-Weather Driver Variables

Schedule	Variables	Comment
Washington:		
Residential Schedule 1	GAS	Ratio of natural gas residential schedule 101 customers to schedule 1 customers in WA.
Industrial Schedules 11, 21, and 25	IP	
Idaho:		
Residential Schedule 1	GAS	Ratio of natural gas residential schedule 101 customers in ID to schedule 1 customers in ID.
Industrial Schedules 11 and 21	IP	

The forecasts for GGDP reflect the average of forecasts from multiple sources. Sources include the Bloomberg survey of forecasts, the Philadelphia Federal Reserve survey of forecasters, the Wall Street Journal survey of forecasters, and other sources. Averaging forecasts reduces the systematic errors of a single-source forecast. This approach assumes that macroeconomic factors flow through UPC in the industrial schedules. This reflects the relative stability of industrial customer growth over the business cycle.

Figure 3.7: Forecasting IP Growth

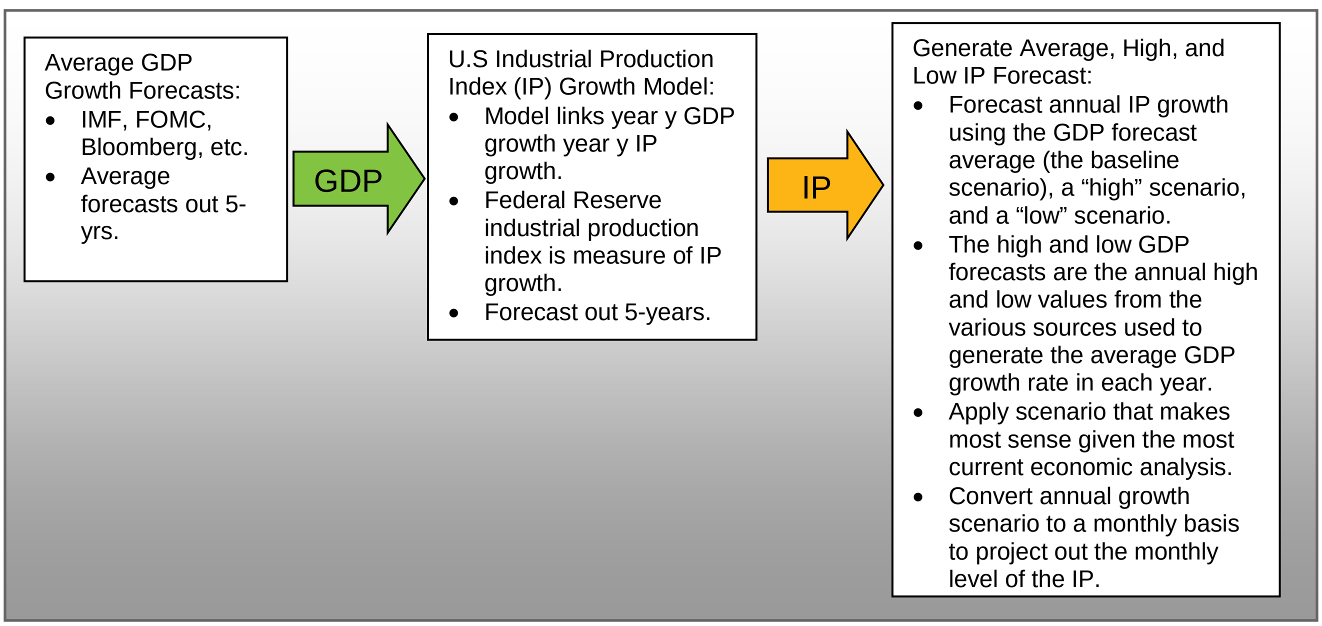
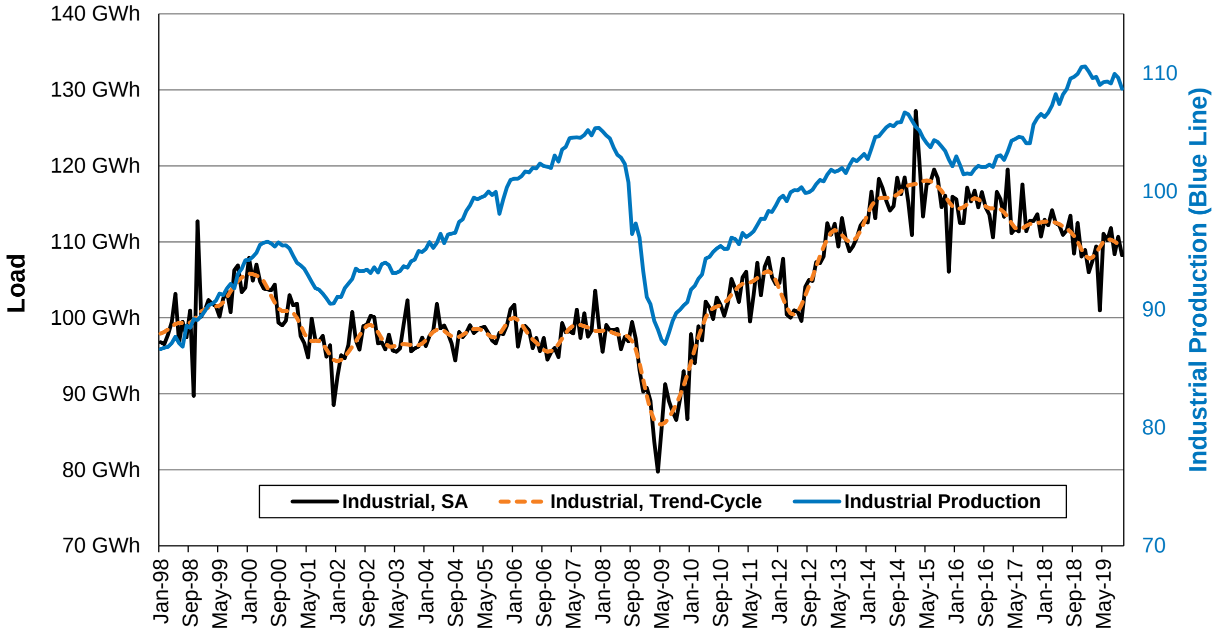


Figure 3.8 shows the historical relationship between the IP and industrial load for electricity.[12,13] The load values have been seasonally adjusted using the Census X11 procedure. The historical relationship is positive for both loads. The relationship is very strong for electricity with the peaks and troughs in load occurring in the same periods as the business cycle peaks and troughs.

Figure 3.8: Industrial Load and Industrial (IP) Index



Customer Forecast Methodology

The econometric modeling for the customer models range from simple smoothing models to more complex autoregressive integrated moving average (ARIMA) models. In some cases, a pure ARIMA model without any structural independent variables is used. For example, the independent variables are only the past values of the schedule customer counts, the dependent variable. Because the customer counts in most schedules are either flat or growing in a stable fashion, complex econometric models are generally unnecessary for generating reliable forecasts. Only in the case of certain residential and commercial schedules is more complex modeling required.

For the main residential and commercial schedules, the modeling approach needs to account for customer growth between these schedules having a high positive correlation over 12-month periods. This high customer correlation translates into a high correlation over the same 12-month periods. Table 3.2 shows the correlation of customer growth between residential, commercial, and industrial users of Avista electricity and natural gas. To assure this relationship in the customer and load forecasts, the models for the Washington and Idaho Commercial Schedules 11 use Washington and Idaho Residential Schedule 1 customers as a forecast driver. Historical and forecasted Residential

[12] Data Source: U.S. Federal Reserve and Avista records.
[13] Figure 3.8 excludes one large industrial customer with significant load volatility.

Schedule 1 customers become drivers to generate customer forecasts for Commercial Schedule 11 customers.

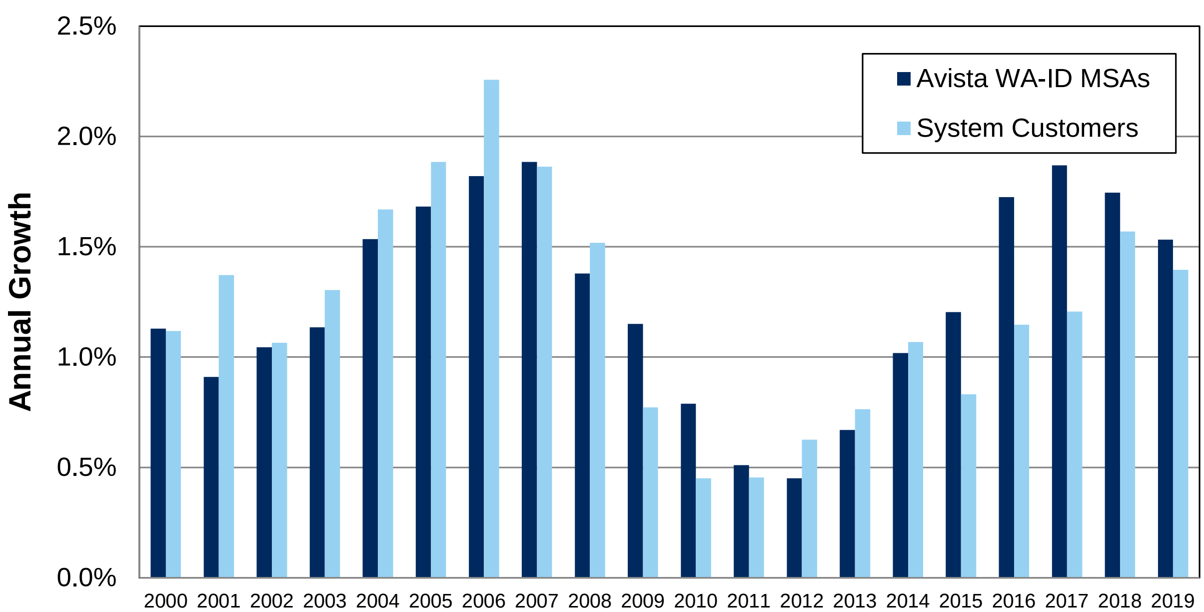
Figure 3.9 shows the relationship between annual population growth and year-over-year customer growth.[14] Customer growth has closely followed population growth in the combined Spokane-Kootenai MSAs over the last 20 years. Population growth averaged 1.3 percent over the 2000-2019 period, and customer growth averaged 1.2 percent annually.

Table 3.2: Customer Growth Correlations, January 1998 – December 2018

Customer Class (Year-over-Year)	Residential	Commercial	Industrial	Streetlights
Residential	1			
Commercial	0.79	1		
Industrial	0.13	0.07	1	
Streetlights	0.10	-0.02	-0.02	1

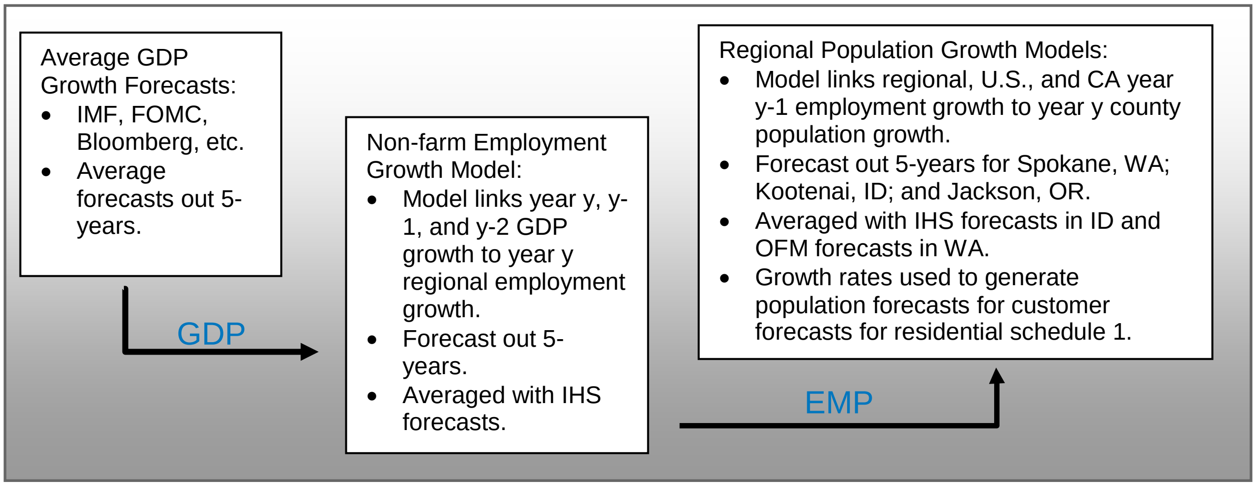
Figure 3.9 demonstrates population growth as a proxy for customer growth. As a result, forecasted population is an adjustment to Residential Schedule 1 customers in Washington and Idaho. The forecast is made using an ARIMA times-series model, for Schedule 1 in Washington and Idaho. If the growth rates generated from this approach differ from forecasted population growth, the forecasts adjust to match forecasted population growth. Figure 3.10 summarizes the forecasting process for population growth for use in Residential Schedule 1 customers.

Figure 3.9: Population Growth vs. Customer Growth, 2000-2019



[14] Data Source: Bureau of Economic Analysis, U.S. Census, Washington State OFM, and Avista records.

Figure 3.10: Forecasting Population Growth



Forecasting population growth is a process that links U.S. GDP growth to service area employment growth and then links regional and national employment growth to service area population growth.

The same average GDP growth forecasts used for the IP growth forecasts are inputs to the five-year employment growth forecast. Avista averages employment forecasts with IHS Connect's (formerly Global Insight) forecasts for the same counties. Averaging may reduce the systematic errors of a single-source forecast. The averaged employment forecasts become inputs to generate population growth forecasts. The forecasting models for regional population growth are in Figure 3.10.

The employment growth forecasts (the average of Avista and IHS forecasts) become inputs generate the population growth forecasts. The Kootenai forecast is averaged with IHS's forecasts for the same MSA. The Spokane forecast is averaged with Washington's Office of Financial Management forecast for the same MSA. These averages produce the final population forecast for each MSA. These forecasts are then converted to monthly growth rates to forecast population levels over the next five years.

IRP Long-Run Load Forecast

The Basic Model

The long-run load forecast extends the five-year projection out to 2045. It includes the electric vehicle (EV) fleets and residential rooftop photovoltaic solar (PV). The long-run modeling approach starts with Equation 3.3.

Equation 3.3: Residential Long-Run Forecast Relationship

$$\ell_y = c_y + u_y$$

Where:

- ℓ_y = residential load growth in year y.
- c_y = residential customer growth in year y.
- u_y = UPC growth in year y.

Equation 3.3 sets annual residential load growth equal to annual customer growth plus the annual UPC growth.[15] C_y is not dependent on weather, so where u_y values are weather normalized, ℓ_y results are weather-normalized. Varying c_y and u_y generates different long-run forecast simulations. This IRP varies c_y for economic reasons and u_y for increased usage of PV, EVs, and LED lighting.

Expected Case Assumptions

The forecast makes assumptions about the long-run relationship between residential, commercial, and industrial classes, as documented below.

1. As noted earlier, long-run residential and commercial customer growth rates are linked, consistent with historical growth patterns that show a positive correlation between the two (see Table 3.2). Figure 3.11 shows the time path of residential customer growth. The average annual growth rate after 2025 is approximately 0.7 percent, with a gradual out to 2045. The generated values shown in Figure 3.11 use the Employment and Population forecasts in conjunction with IHS's employment and population forecasts and Washington's OFM population forecasts. Starting in 2026, it assumed that annual commercial customer growth is 0.78 times residential customer growth. This number is the median ratio of commercial customer growth to residential customer growth since 2005. The annual average growth rate of commercial customers after 2025 is approximately 0.5%. The annual industrial customer growth rate assumption is -0.3% after 2025, which is equivalent to a decline of four industrial customers a year out to 2045. This assumption reflects an ongoing long-run decline in industrial customers.

2. Commercial load growth follows changes in residential load growth. This positive correlation assumption is consistent with the high historical correlation between residential and commercial load growth. The connection, based on a linear regression

[15] Since UPC = load/customers, calculus shows the annual percentage change UPC ≈ percentage change in load - percentage change in customers. Rearranging terms, the annual percentage change in load ≈ percentage change in customers + percentage change in UPC.

linking commercial UPC growth to residential UPC growth, assumes that for every 1 percent point change in residential UPC growth, commercial UPC will change by 0.29 percent.

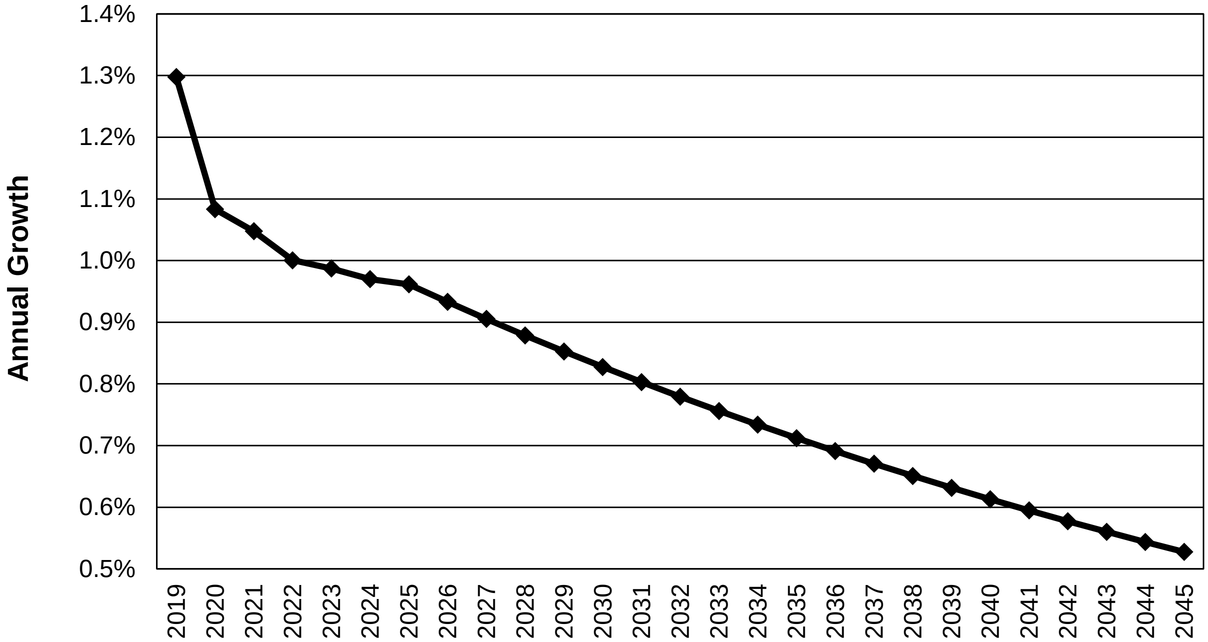
3. Consistent with historical behavior, industrial and streetlight load growth projections do not correlate with residential or commercial load. Annual industrial load growth is set at -0.3 percent after 2025 and streetlight load growth at 0 percent after 2025. Both growth rates are in the range of historical norms and forecasted growth trends from the five-year model.

4. As noted earlier, the assumption in the five-year forecast for this IRP is for RAP to be constant out to 2025; increase at 1 percent between 2026 and 2029; and then increase 1.5 percent until 2045. RAP no longer appears explicitly in the regression equations for the five-year forecast. The coefficient estimates for RAP have become unstable and statistically insignificant. Therefore, the 2020 IRP assumes own-price elasticity to be -0.3 percent, based on long-run estimates from academic literature.

5. Avista estimates 800 Electric Vehicles (EV) in its service area through 2019. The forecasted rate of adoption over the 2020-2045 period uses a weighted average of the EV forecast provided by Avista's EV management team. This forecast reflects a low, middle, and high forecast for EVs in our electric service area. The low forecast predicts 45,000 EVs by 2045; the middle predicts 100,000; and the high predicts 250,000. The final 2045 forecast used for the IRP weights the low forecast at 50 percent, the middle at 30 percent weight; and the high with a 20 percent weight. Therefore, the IRP forecast for 2040 is 0.50 x 45,000 + 0.30 x 100,000 + 0.20 x 250,000 = 102,500 EVs. Between 2020 and 2045, the implied growth rate is 19 percent, which puts total EVs in 2045 as 102,500. The forecast assumes each EV uses 3,500 kWh per year.

6. Rooftop PV penetration, measured as the share of PV residential customers to total residential customers, continues to grow at present levels in the forecast. The average PV system is forecast at the current median of 7.0 kW (DC) and a 13 percent capacity factor, or about 7,800 kWh per year per customer. The forecast assumes this median system size will increase 1 percent annually to about 10,100 kWh per year per customer in 2045. The IRP assumes the penetration rate (share of residential customers) will continue to follow a non-linear relationship between the historical penetration rate in year t and the historical number of residential customers in year t. Under this assumption, residential PV penetration will increase from 0.25 percent in 2019 to about 2 percent in 2037. Although not directly calculated, the impact of PV penetration for commercial customers is indirectly accounted for by the assumed positive correlation between residential and commercial UPC.

Figure 3.11: Long-Run Annual Residential Customer Growth



Native Load Scenarios with Low/High Economic Growth

The high and low load scenarios use population growth Equations 3.6 and 3.7, holding long-run U.S. employment growth constant at 0.6 percent (an IHS forecast), but varying MSA employment growth at higher and lower levels to gauge the impacts on population growth and utility loads. See Table 3.3. The high/low range for growth in service area employment reflects historical employment growth variability. Simulated population growth is a proxy for residential and customer growth in the long-run forecast model, and produces the high and low native load forecasts shown in Figure 3.12.

Table 3.3: High/Low Economic Growth Scenarios (2020-2045)

Economic Growth	Annual U.S. Employment Growth (percent)	Annual Service Area Employment Growth (percent)	Annual Population Growth (percent)
Expected Case	0.60	0.90	0.78
High Growth	0.60	1.80	1.20
Low Growth	0.60	0.60	0.60

Figure 3.12: Average Megawatts, High/Low Economic Growth Scenarios

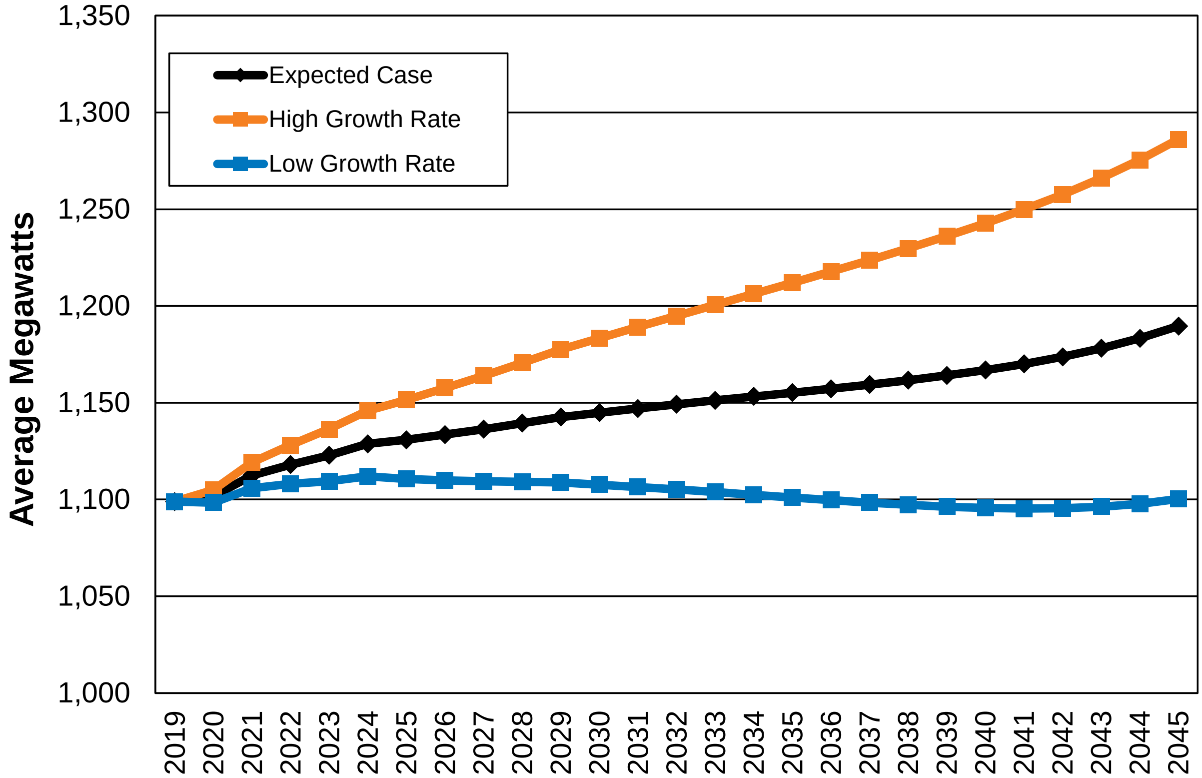


Table 3.4 is the average annual load growth rate over the 2020-2045 period. The low growth scenario predicts a slight load decline over 2025-2041.

Table 3.4: Load Growth for High/Low Economic Growth Scenarios (2020-2045)

Economic Growth	Average Annual Native Load Growth (percent)
Expected Case	0.30
High Growth	0.60
Low Growth	0.00

Long-Run Forecast Residential Retail Sales

Focusing on residential kWh sales, Figure 3.13 is the residential UPC growth plotted against the EIA's annual growth forecast of U.S. residential use per household growth. The EIA's forecast is from the 2019 Annual Energy Outlook. Both Avista's and EIA's forecasts show positive UPC growth in the early 2040s. The EIA forecast reflects a population shift to warmer-climate states where air conditioning is typically required most of the year. In contrast, Avista's forecast growth reflects the impact of EVs.

Figure 3.13: UPC Growth Forecast Comparison to EIA

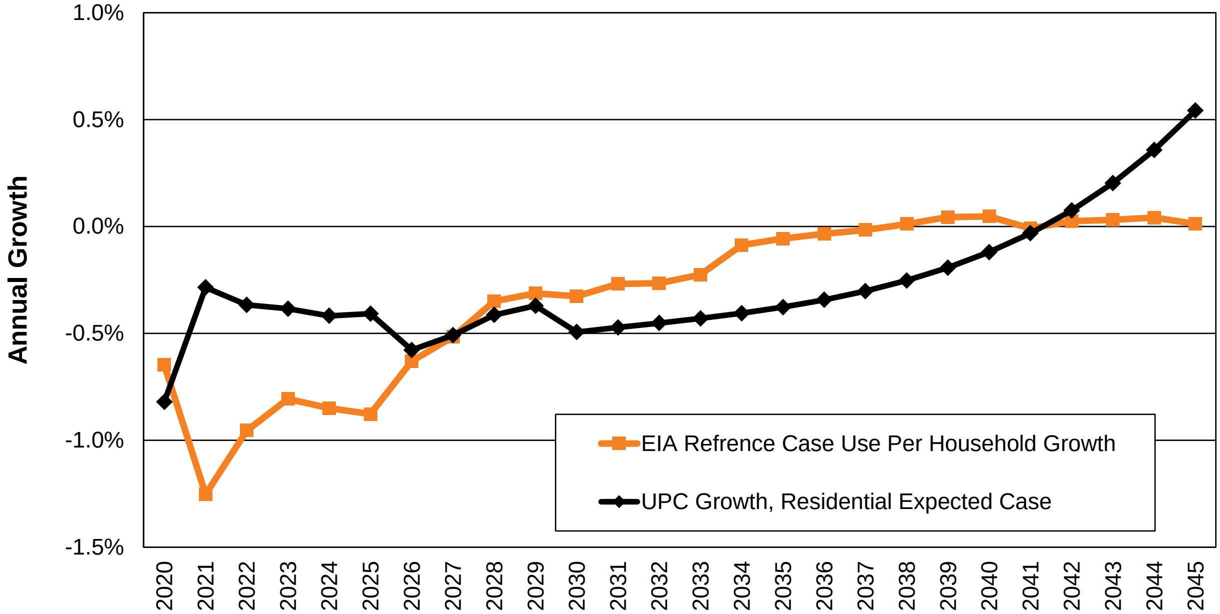
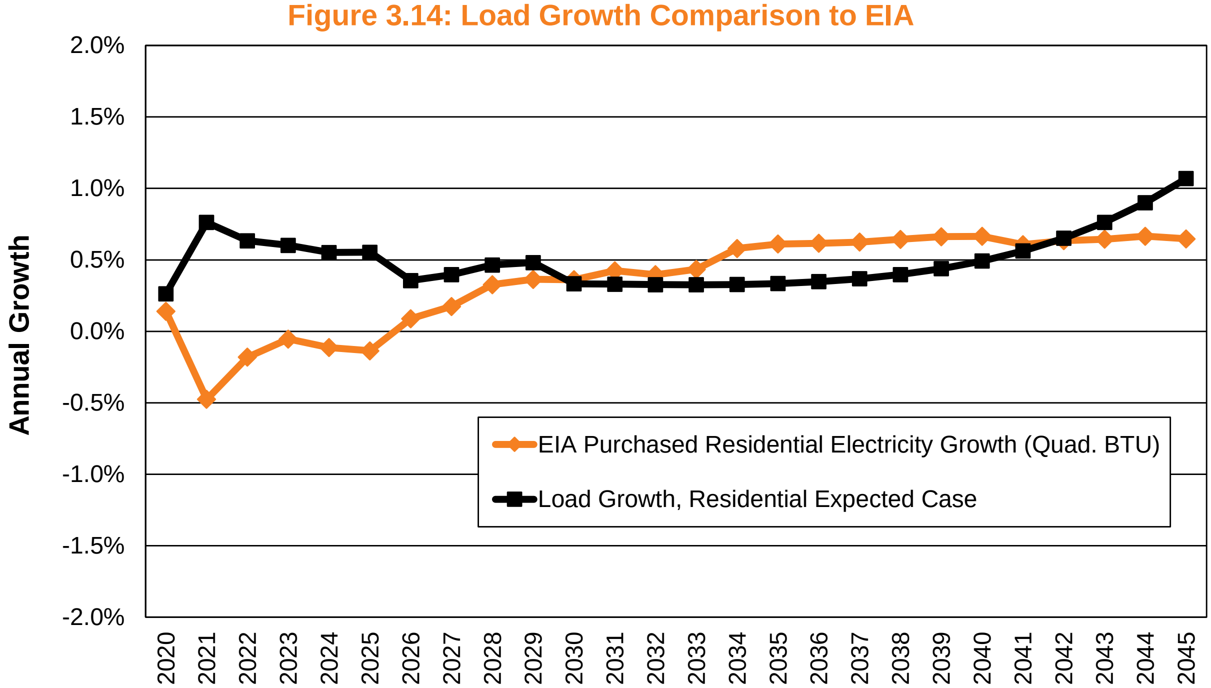


Figure 3.14 shows the EIA and the residential load growth forecasts. Avista's forecast is higher in the 2020-2029 period, reflecting an assumption that service area population growth will be stronger than the U.S. average, consistent with government and IHS forecasts for the far west and Rocky Mountain regions where Avista's service territory is located.

Figure 3.14: Load Growth Comparison to EIA



Monthly Peak Load Forecast Methodology

The Peak Load Regression Model

The peak load forecast helps Avista determine the amount of resources necessary to meet peak demand. In particular, Avista must build generation capacity to meet winter and summer peak periods. Looking forward, the highest peak loads are most likely to occur in the winter months, although in some years a mild winter followed by a hot summer could find the annual maximum peak load occurring in a summer hour. On a planning basis where we expect extreme weather to occur in the winter, peak loads occur in the winter throughout the IRP timeframe. Equation 3.9 shows the current peak load regression model.

Equation 3.4: Peak Load Regression Model

$$hMW_{d,t,y}^{netpeak} = \lambda_0 + \lambda_1 HDD_{d,t,y} + \lambda_2 (HDD_{d,t,y})^2$$
$$+ \lambda_3 HDD_{d-1,t,y} + \lambda_4 CDD_{d,t,y} + \lambda_5 CDD_{d,t,y}^{HIGH} + \lambda_6 CDD_{d-1,t,y} + \phi_1 GDP_{t.y-1}$$
$$+ \phi_2 (D_{SUM,2014\uparrow} * GDP_{t.y-1}) + \boldsymbol{\omega_{WD} D_{d,t,y}} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Mar\ 2005=1}$$
$$+ \epsilon_{d,t,y}\ for\ t, y = June\ 2004 \uparrow$$

Where:

- $\mathrm{hMW}_{\mathrm{d,t,y}}^{\mathrm{netpeak}}$ = metered peak hourly usage on day of week d, in month t, in year y, and excludes two large industrial producers. The data series starts in June 2004.
- $\mathrm{HDD}_{\mathrm{d,t,y}}$ and $\mathrm{CDD}_{\mathrm{d,t,y}}$ = heating and cooling degree days the day before the peak.
- $(\mathrm{HDD}_{\mathrm{d,t,y}})^2$ = squared value of $HDD_{d,t,y}$.$\mathrm{HDD}_{\mathrm{d-1,t,y}}$ and $\mathrm{CDD}_{\mathrm{d-1,t,y}}$ = heating and cooling degree days the day before the peak.
- $\mathrm{CDD}_{\mathrm{d,t,y}}^{\mathrm{HIGH}}$ = maximum peak day temperature minus 65 degrees.[16]
- $\mathrm{GDP}_{\mathrm{t.y-1}}$ = extrapolated level of real GDP in month t in year y-1.
- $(D_{SUM,2014\uparrow} * GDP_{t.y-1})$ is a slope shift variable for GDP in the summer months, June, July, and August.
- $\omega_{WD}D_{d,t,y}$ = dummy vector indicating the peak's day of week.
- $\omega_{SD}D_{t,y}$ = seasonal dummy vector indicating the month; and the other dummy variable control for an extreme outliers in March 2005.
- $\varepsilon_{d,t,y}$ = uncorrelated N(0, σ) error term.

Generating Weather Normal Growth Rates Based on a GDP Driver

Equation 3.4 coefficients identify the month and day most likely to result in a peak load in the winter or summer. By assuming normal peak weather and switching on the dummy variables for day (d_{MAX}) and month (t_{MAX}) that maximize weather normal peak conditions in winter and summer, a series of peak forecasts from the current year, y_c, are generated

[16] This term provides a better model fit than the square of CDD.

out N years by using forecasted levels of GDP as shown in Equation 3.3.[17] All other factors besides GDP remain constant to determine the impact of GDP on peak load. For winter, this is defined as the forecasted series W:

$$W = \{F(hMW_{d_{MAX},t_{MAX},y_c+1}^{WN,netpeak,W}), F(hMW_{d_{MAX},t_{MAX},y_c+2}^{WN,netpeak,W}), \dots, F(hMW_{d_{MAX},t_{MAX},y_c+N}^{WN,netpeak,W})\}$$

For summer, this is defined as the forecasted series S:

$$S = \{F(hMW_{d_{MAX},t_{MAX},y_c+1}^{WN,netpeak,S}), F(hMW_{d_{MAX},t_{MAX},y_c+2}^{WN,netpeak,S}), \dots, F(hMW_{d_{MAX},t_{MAX},y_c+N}^{WN,net\,peak,S})\}$$

Both S and W are convertible to a series of annual growth rates, GhMW. Peak load growth forecast equations are shown below as winter (W_G) and summer (S_G.):

$$W_G = \{F(GhMW_{d_{MAX},t_{MAX},y_c+1}^{WN,netpeak,W}), F(GhMW_{d_{MAX},t_{MAX},y_c+2}^{WN,netpeak,W}), \dots, F(GhMW_{d_{MAX},t_{MAX},y_c+N}^{WN,netpeak,W})\}$$

$$S_G = \{F(GhMW_{d_{MAX},t_{MAX},y_c+1}^{WN,netpeak,S}), F(GhMW_{d_{MAX},t_{MAX},y_c+2}^{WN,netpeak,S}), \dots, F(GhMW_{d_{MAX},t_{MAX},y_c+N}^{WN,netpeak,S})\}$$

In Equation 3.5, holding all else constant, growth rates are applied to simulated peak loads generated for the current year, y_c, for each month, January through December. These peak loads are generated by running actual extreme weather days observed since 1890. The following section describes this process.

Simulated Extreme Weather Conditions with Historical Weather Data

Equation 3.5 generates a series of simulated extreme peak load values for heating degree days.

Equation 3.5: Peak Load Simulation Equation for Winter Months

$$\widehat{hMW}_{t,y}^{W} = a + \widehat{\lambda_1} HDD_{t,y,MIN} + \widehat{\lambda_2}(HDD_{t,y,MIN})^2 \; for \; t = Jan, \dots, Dec \; if \; maxium \; avg.temp < 65 \; and \; y = 1890, \dots, y_c$$

Where:

- $\widehat{\mathrm{hMW}}_{\mathrm{t,y}}^{\mathrm{W}}$ = simulated winter peak megawatt load using historical weather data.
- $HDD_{t,y,MIN}$ = heating degree days calculated from the minimum (MIN) average temperature (average of daily high and low) on day d, in month t, in year y if in month t the maximum average temperature (average of daily high and low) is less than 65 degrees.
- a = aggregate impact of all the other variables held constant at their average values.

[17] Forecasted GDP is generated by applying the averaged GDP growth forecasts used for the employment and industrial production forecasts discussed previously.

Similarly, the model for cooling degree days is:

Equation 3.6: Peak Load Simulation Equation for Summer Months

$$\widehat{hMW}_{t,y}^{S} = a + \widehat{\lambda_4}CDD_{t,y,MAX} \ for \ t = Jan, \dots, Dec \ if \ maxium \ avg.temp > 65 \ and \ y = 1890, \dots, y_c$$

Where:

- $\widehat{\mathrm{hMW}}_{\mathrm{t,y}}^{\mathrm{S}}$ = simulated winter peak megawatt load using historical weather data.
- $CDD_{t,y,MAX}$ = cooling degree days calculated from the maximum (MAX) average temperature. The average of daily high (H) and low (L) on day d, in month t, in year y if in month t if the maximum average temperature (average of daily high and low) is greater than 65 degrees.
- a = aggregate impact of all the other variables held constant at their average values.

With over 100 years of average maximum and minimum temperature data, Equations 3.10 and 3.11 applied to each month t will produce over 100 simulated values of peak load that can be averaged to generate a forecasted average peak load for month t in the current year, y_c. Equations 3.7 and 3.8 show the average for each month.

Equation 3.7: Current Year Peak Load for Winter Months

$$F\left(hMW_{t,y_c}^{W}\right) = \frac{1}{(y_c - 1890) + 1}\sum_{y=1890}^{y_c} \widehat{hMW}_{t,y}^{W} \ for \ each \ heating \ month \ t \ where \ maxium \ avg.temp < 65$$

Equation 3.8: Current Year Peak Load for Summer Months

$$F\left(hMW_{t,y_c}^{S}\right) = \frac{1}{(y_c - 1890) + 1}\sum_{y=1890}^{y_c} \widehat{hMW}_{t,y}^{S} \ for \ each \ cooling \ month \ t \ where \ maxium \ avg.temp > 65$$

Forecasts beyond y_c are generated using the appropriate growth rate from series W_G and S_G. For example, the forecasts for y_{c+1} for winter and summer are:

$$F\left(hMW_{t,y_{c+1}}^{WN,netpeak,W}\right) = F\left(hMW_{t,y_c}^{W}\right) * [1 + F(GhMW_{d_{MAX},t_{MAX},y_c+1}^{WN,netpeak,W})]$$

$$F\left(hMW_{t,y_{c+1}}^{WN,netpeak,S}\right) = F\left(hMW_{t,y_c}^{S}\right) * [1 + F(GhMW_{d_{MAX},t_{MAX},y_c+1}^{WN,netpeak,S})]$$

The finalization of the peak load forecast occurs when the forecasted peak loads of two large industrial customers and EVs, excluded from the Equation 3.7 and 3.8 estimations, are added back in.

Table 3.5 shows estimated peak load growth rates with and without the two large industrial customers. Figure 3.15 shows the forecasted time path of peak load out to 2045, and Figure 3.16 shows the high/low bounds based on a one-in-20 event (95 percent confidence interval) using the standard deviation of the simulated peak loads from Equations 3.7 and 3.8.

Table 3.5: Forecasted Winter and Summer Peak Growth, 2020-2045

Category	Winter (Percent)	Summer (Percent)
Including Large Industrial Customers	0.34	0.44

Table 3.6 shows how the summer peak forecast grows faster than the winter peak. Under current growth forecasts, the orange summer line in Figure 3.15 will get close to the blue winter line by 2045. Figure 3.16 shows that the winter high/low bound considerably larger than summer, and reflects a greater range of temperature anomalies in the winter months. Table 3.6 shows the energy and peak forecasts.

Figure 3.15: Peak Load Forecast 2020-2045

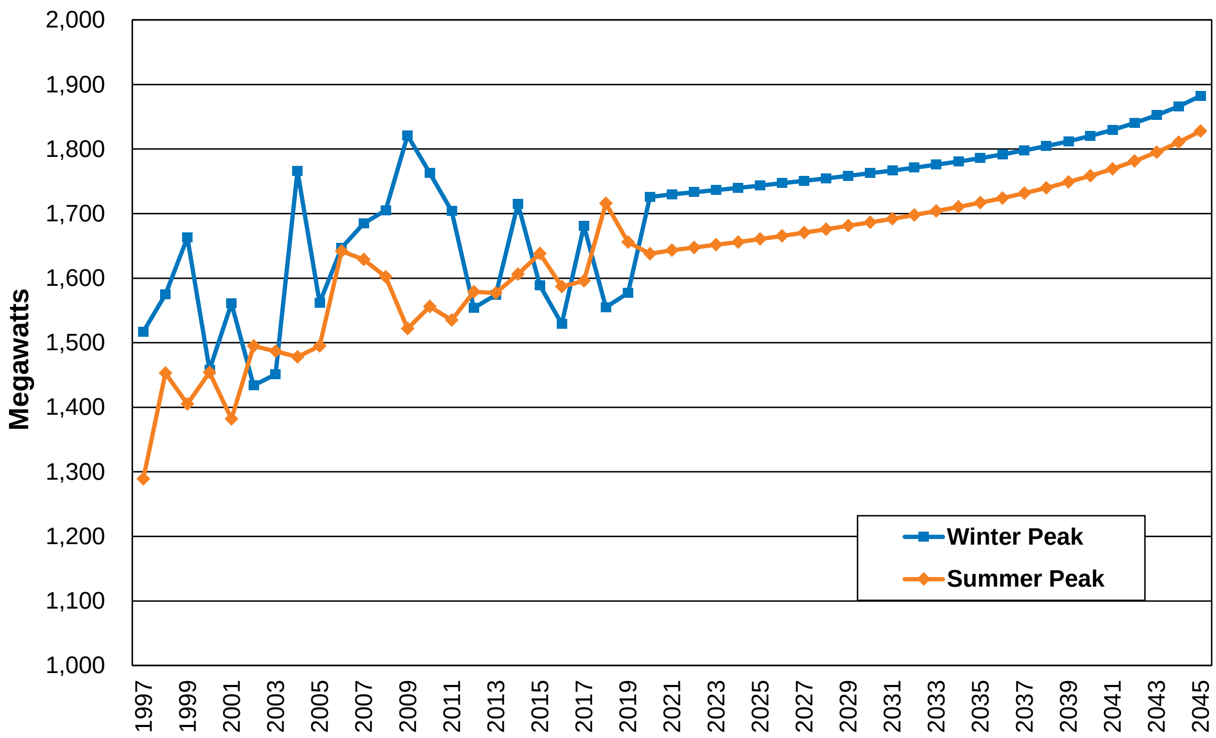


Figure 3.16: Peak Load Forecast with 1 in 20 High/Low Bounds, 2020-2045

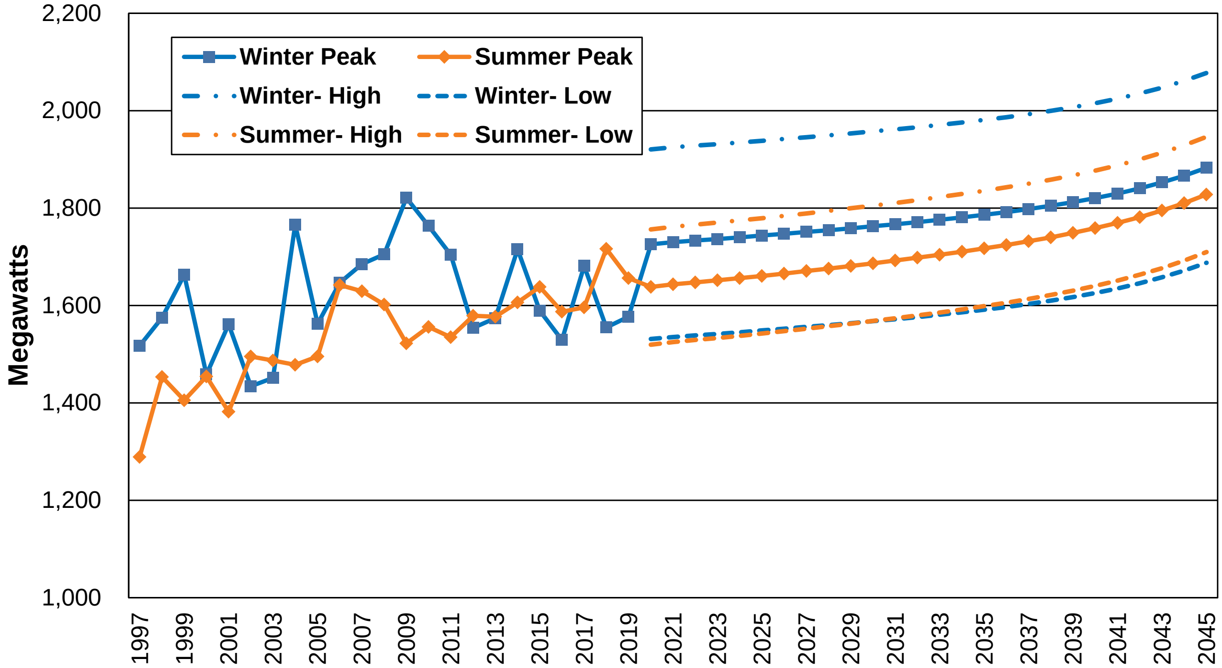


Table 3.6: Energy and Peak Forecasts

Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)
2020	1,102	1,726	1,638
2021	1,112	1,730	1,643
2022	1,118	1,733	1,648
2023	1,123	1,736	1,652
2024	1,129	1,740	1,656
2025	1,131	1,743	1,661
2026	1,134	1,747	1,666
2027	1,136	1,751	1,671
2028	1,139	1,754	1,676
2029	1,143	1,758	1,681
2030	1,145	1,762	1,686
2031	1,147	1,767	1,692
2032	1,149	1,771	1,698
2033	1,151	1,776	1,704
2034	1,153	1,781	1,710
2035	1,155	1,786	1,717
2036	1,157	1,792	1,724
2037	1,159	1,798	1,732
2038	1,162	1,805	1,740
2039	1,164	1,812	1,749
2040	1,167	1,820	1,759
2041	1,170	1,830	1,769
2042	1,174	1,840	1,781
2043	1,178	1,852	1,795
2044	1,183	1,866	1,810
2045	1,190	1,882	1,828

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4. Existing Supply Resources

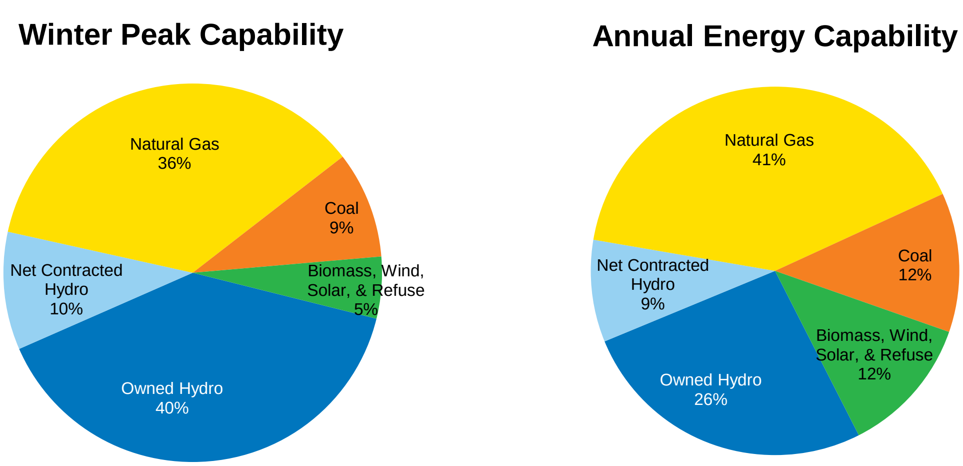
Avista relies on a diverse portfolio of assets to meet customer loads, including owning and operating eight hydroelectric developments on the Spokane and Clark Fork rivers. Its thermal assets include ownership of five natural gas-fired projects, a biomass plant, and partial ownership of two coal-fired units. Avista also purchases energy from several independent power producers (IPPs) and regional utilities.

Section Highlights

- Hydroelectric represents about half of Avista's winter generating capability.
- Natural gas-fired plants represent the largest portion of Avista's thermal generation portfolio.
- Since the 2017 IRP, Avista signed PPAs for new solar and wind projects.
- Twelve percent of Avista's generating potential is biomass, wind, solar, or refuse.
- Avista's net metering program includes 1,046 customers with 8.6 megawatts of their own generation.

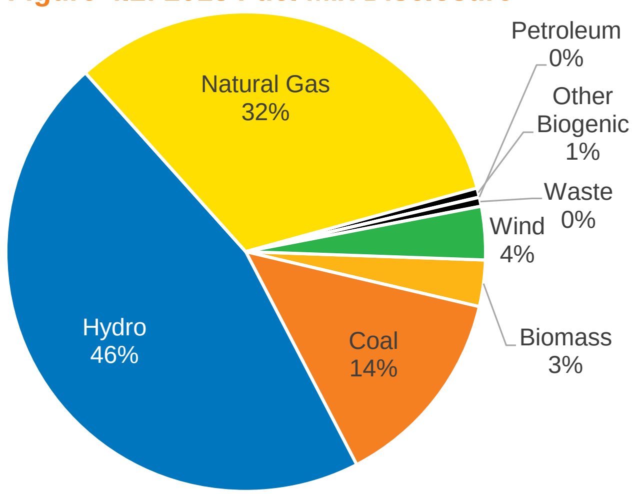
Figure 4.1 shows Avista's capacity and energy mixes. Winter capability is the share of total capability of each resource type the utility can rely upon to meet winter peak load. The annual energy chart represents the energy as a percent of total supply; this calculation includes fuel limitations (for water, wind, and wood), maintenance and forced outages. Avista's largest energy supply in the peak winter months is from hydroelectric at 50 percent, followed by natural gas-fired resources at 36 percent. On an energy capability basis, natural gas-fired generation can produce more energy, at 41 percent, than hydroelectric at 35 percent because it is not constrained by fuel limitations. In any given year, the resource mix will change depending on streamflow conditions and market prices.

Figure 4.1: 2020 Avista Capability and Energy Fuel Mix



Avista reports its fuel mix annually in the Washington State Fuel Mix Disclosure[1]. The State calculates the resource mix used to serve load, rather than generation potential, by adding regional[2] estimates for unassigned market purchases and Avista-owned generation minus the environmental attributes from renewable energy credit (REC) sales[3]. Figure 4.2 shows Avista's 2018 fuel mix disclosure from the Washington State Department of Commerce as of November 8, 2019. Idaho customer's fuel mix is nearly identical to this report with the exception of purchases of PURPA generation. Each state receives RECs based on their share of the system (approximately 65 percent Washington and 35 percent Idaho). Avista may retain RECs, sell them to other parties, or transfer them between states. An example of REC transfers between states entails RECs used to comply with Washington's Energy Independence Act (EIA). In this case, Idaho transfers its share of qualifying RECs to Washington customers in exchange for a reduction in rates for Idaho customers. This fuel mix disclosure includes regionally assigned fuel mix where Avista sells RECs to others.

Figure 4.2: 2018 Fuel Mix Disclosure



Spokane River Hydroelectric Developments

Avista owns and operates six hydroelectric developments on the Spokane River. Five operate under a 50-year FERC operating license through June 18, 2059. The sixth, Little Falls, operates under separate authorization from the U.S. Congress[4]. This section describes the Spokane River developments and provides the maximum on-peak and nameplate capacity ratings for each plant. The maximum on-peak capacity of a generating unit is the total amount of electricity it can safely generate with its existing

[1] http://www.commerce.wa.gov/wp-content/uploads/2019/12/2018-Preliminary-Disclosure-Data-03122019.pdf

[2] For 2018, the region is approximately 46 percent hydroelectric, 23 percent coal, 15 percent natural gas, 3 percent nuclear, 8 percent wind, and 4 percent other.

[3] In 2018, Avista sold 56 aMW of RECs, which lowers the percentage of renewable resources.

[4] Little Falls is not under FERC jurisdiction as it was congressionally authorized because of its location on the Spokane Indian Reservation. Avista operates Little Falls Dam in accordance with an agreement reached with the Tribe in 1994 to identify operational and natural resource requirements. Little Falls Dam is also subject to other Washington State environmental and dam safety requirements.

configuration and the current mechanical state of the facility. This capacity is often higher than the nameplate rating for hydroelectric developments because of plant upgrades and favorable head or streamflow conditions. The nameplate, or installed capacity, is the capacity of a plant as rated by the manufacturer. All six hydroelectric developments on the Spokane River connect directly to the Avista electrical system. Avista also provides historical operating data for each of the projects for 2014 through 2018 in Appendix C – Historical Generation Operating Data (Confidential).

Post Falls

Post Falls is the hydroelectric facility furthest upstream on the Spokane River. It is located several miles east of the Washington/Idaho border. The facility began operating in 1906 and during summer months maintains the elevation of Lake Coeur d'Alene. Post Falls has a 14.75 MW nameplate rating and is capable of producing up to 18.0 MW with its six generating units. Chapter 9 - Supply-Side Resource Options provides details about potential modernization options under consideration at Post Falls.

Upper Falls

The Upper Falls development sits within the boundaries of Riverfront Park in downtown Spokane. It began generating in 1922. The project is comprised of a single 10.0 MW nameplate unit with a 10.26 MW maximum capacity rating.

Monroe Street

Monroe Street was Avista's first generation development. It began serving customers in 1890 in downtown Spokane near Riverfront Park. Following a complete rehabilitation in 1992, the single generating unit has a 14.8 MW nameplate rating and a 15.0 MW maximum capacity rating.

Nine Mile

A private developer built the Nine Mile development in 1908 near Nine Mile Falls, Washington. Avista purchased the project in 1925 from the Spokane & Inland Empire Railroad Company. Nine Mile has undergone recent substantial upgrades. The development has two new 8 MW units and two 10 MW units for a total nameplate rating of 36 MW. The incremental generation from the upgrades qualifies for Washington's EIA.

Long Lake

The Long Lake development is located northwest of Spokane and maintains the Lake Spokane reservoir, also known as Long Lake. The project's four units have a nameplate rating of 81.6 MW and 88.0 MW of combined capacity. Chapter 9 - Supply-Side Resource Options provides details about potential modernization options under consideration at Long Lake.

Little Falls

The Little Falls development, completed in 1910 near Ford, Washington, is the furthest downstream hydroelectric facility on the Spokane River. The facility's four units generate 35.2 MW of on-peak capacity and have a 32.0 MW nameplate rating.

Clark Fork River Hydroelectric Development

The Clark Fork River Development includes hydroelectric projects located near Clark Fork, Idaho, and Noxon, Montana, 70 miles south of the Canadian border. The plants operate under a FERC license through 2046. Both hydroelectric projects on the Clark Fork River connect to the Avista transmission system.

Noxon Rapids

The Noxon Rapids development includes four generators installed between 1959 and 1960, and a fifth unit that entered service in 1977. Avista completed major turbine upgrades on units 1 through 4 between 2009 and 2012. The upgrades increased the capacity of each unit from 105 MW to 112.5 MW and added 6.6 aMW of additional energy. The incremental generation from the upgrades qualifies for the EIA.

Cabinet Gorge

Cabinet Gorge started generating power in 1952 with two units, and added two additional generators the following year. Upgrades to units 1 through 4 occurred in 1994, 2004, 2001, and 2007. The current maximum on-peak plant capacity is 270.5 MW; it has a nameplate rating of 265.2 MW. The incremental generation from the upgrades qualifies for the EIA.

Total Hydroelectric Generation

Avista's hydroelectric plants have 1,080 MW of on-peak capacity. Table 4.1 summarizes the location and operational capacities of Avista's hydroelectric projects and the expected energy output of each facility based on an 80-year hydrologic record.

Table 4.1: Avista-Owned Hydroelectric Resources

Project Name	River System	Location	Nameplate Capacity (MW)	Maximum Capability (MW)	Expected Energy (aMW)
Monroe Street	Spokane	Spokane, WA	14.8	15.0	11.2
Post Falls	Spokane	Post Falls, ID	14.8	18.0	9.4
Nine Mile	Spokane	Nine Mile Falls, WA	36.0	32.0	15.7
Little Falls	Spokane	Ford, WA	32.0	35.2	22.6
Long Lake	Spokane	Ford, WA	81.6	89.0	56.0
Upper Falls	Spokane	Spokane, WA	10.0	10.2	7.3
Noxon Rapids	Clark Fork	Noxon, MT	518.0	610.0	196.5
Cabinet Gorge	Clark Fork	Clark Fork, ID	265.2	270.5	123.6
Total			**972.4**	**1,079.9**	**442.3**

Thermal Resources

Avista owns seven thermal generation assets located across the Northwest. The resources provide dependable energy and capacity serving base-load and peak-load obligations. Table 4.2 summarizes resources by fuel type, online year, remaining life, book value at the end of 2018, and remaining accounting life. Appendix C provides operating details for these facilities between 2014 and 2018. Table 4.3 includes capacity information for each of the facilities along with the five-year historical forced outage rates used for modeling purposes. Plants with a number in parentheses indicates the number of equally sized units at each facility.

Table 4.2: Avista-Owned Thermal Resources

Project Name	Location	Fuel Type	Start Date	Remaining Design Life	Book Value (mill. $)	Book Life (years)
Colstrip 3 & 4	Colstrip, MT	Coal	1984[5]	25	121.4	See Note[6]
Rathdrum	Rathdrum, ID	Gas	1995	40	36.5	14
Northeast	Spokane, WA	Gas	1978	15	0.6	<2
Boulder Park	Spokane, WA	Gas	2002	25	17.4	20
Coyote Springs 2	Boardman, OR	Gas	2003	25	124.8	21
Kettle Falls	Kettle Falls, WA	Wood	1983	20	41.6	14
Kettle Falls CT	Kettle Falls, WA	Gas	2002	40	3.7	24

Table 4.3: Avista-Owned Thermal Resource Capability

Project Name	Winter Maximum Capacity (MW)	Summer Maximum Capacity (MW)	Nameplate Capacity (MW)	Forced Outage Rate (%)
Colstrip 3	111	111	123.5	9.3
Colstrip 4	111	111	123.5	9.3
Rathdrum (2 units)	176	130	166.5	5.0
Northeast (2 units)	66	42	61.2	5.0
Boulder Park (6 units)	24.6	24.6	24.6	13.7
Coyote Springs 2	317.5	286	287.3	2.6
Kettle Falls	47	47	50.7	2.4
Kettle Falls CT	11	8	7.5	5.0
Total	**864.1**	**759.6**	**844.8**	

Colstrip Units 3 and 4

The Colstrip plant, located in eastern Montana, consists of four coal-fired steam plants connected to a double-circuit 500 kV line owned by each of the participating utilities. The utility-owned segment extends from Colstrip to Townsend, Montana. BPA's ownership of the 500 kV line starts in Townsend and continues west. Energy moves across both segments of the transmission line under a long-term wheeling arrangement.

[5] Colstrip unit 3 began in 1984 and Colstrip 4 began in 1986.
[6] Avista is modeling Colstrip Units 3 and 4 with a depreciable life ending in 2025 in Washington and 2027 in Idaho. Avista has received approval for the 2025 life in Washington, but has not received authorization in Idaho to recover all costs through 2027.

Talen Energy Corporation operates the facilities on behalf of the six owners. Avista has no ownership interest in Units 1 or 2 (closed in January 2020), but owns 15 percent of Units 3 and 4. Unit 3 began operating in 1984 and Unit 4 was finished in 1986. Avista's share of Colstrip has a maximum net capacity of 222 MW, and a nameplate rating of 247 MW.

Rathdrum

Rathdrum consists of two identical simple-cycle combustion turbine (CT) units. This natural gas-fired plant located near Rathdrum, Idaho connects to the Avista transmission system. It entered service in 1995 and has a maximum combined capacity of 176 MW in the winter and 126 MW in the summer. The nameplate rating is 166.5 MW.

Northeast

The Northeast plant, located in Spokane, has two identical aero-derivative simple-cycle CT units completed in 1978. It connects to Avista's transmission system. The plant is capable of burning natural gas or fuel oil, but current air permits preclude the use of fuel oil. The combined maximum capacity of the units is 68 MW in the winter and 42 MW in the summer, with a nameplate rating of 61.2 MW. The plant air permit limits run hours to 100 per year.

Boulder Park

The Boulder Park project entered service in the Spokane Valley in 2002 and connects directly to the Avista transmission system. The site uses six identical natural gas-fired internal combustion reciprocating engines to produce a combined maximum capacity and nameplate rating of 24.6 MW.

Coyote Springs 2

Coyote Springs 2 is a natural gas-fired combined cycle combustion turbine (CCCT) located near Boardman, Oregon. The plant connects to the BPA 500 kV transmission system under a long-term agreement. The plant began service in 2003; it has a maximum capacity of 317.5 MW in the winter and 285 MW in the summer with duct burners. The nameplate rating of the plant is 287.3 MW.

Kettle Falls Generation Station and Kettle Falls Combustion Turbine

The Kettle Falls Generating Station, a woody biomass facility, entered service in 1983 near Kettle Falls, Washington. It is among the largest biomass generation plants in North America and connects to Avista on its 115 kV transmission system. The open-loop biomass steam plant uses waste wood products (hog fuel) from area mills and forest slash, but can also burn natural gas. A 7.5 MW combustion turbine (CT), added to the facility in 2002, burns natural gas and increases overall plant efficiency by sending exhaust heat to the wood boiler.

The wood-fired portion of the plant has a maximum capacity of 50 MW, and its nameplate rating is 50.7 MW. The plant typically operates between 45 and 47 MW because of fuel conditions that change depending on the moisture content of the hog fuel. The plant's capacity increases to 55 to 58 MW when operated in combined-cycle mode with the CT. The CT produces 8 MW of peaking capability in the summer and 11 MW in the winter. The CT resource can be limited in the winter when the natural gas pipeline is capacity constrained. For IRP modeling, the CT does not run when temperatures fall below zero[7]. This operational assumption reflects natural gas availability limits on the plant when local natural gas distribution demand is highest.

Small Avista-Owned Solar

Avista has three small projects of its own. The first solar project was three kilowatts on its corporate headquarters as part of the Solar Car initiative. The solar production helped power two electric vehicles in the corporate fleet. Avista installed a 15-kilowatt solar system in Rathdrum, Idaho to supply Buck-A-Block, a voluntary program allowing customers to purchase green energy. The 423-kW Avista Community Solar project, located at the Boulder Park property, entered service in 2015.

Table 4.4: Avista-Owned Solar Resource Capability

Project Name	Project Location	Project Capacity (kW-DC)
Spokane Headquarters Solar	Spokane, WA	3
Rathdrum Solar	Rathdrum, ID	15
Boulder Park Solar	Spokane Valley, WA	423
Total		**441**

Power Purchase and Sale Contracts

Avista uses purchase and sale arrangements of varying lengths to meet a portion of its load requirements. Contracts provide many benefits, including environmentally low-impact and low-cost hydroelectric and wind power. This chapter describes the contracts in effect during the timeframe of the 2020 IRP. Tables 4.4 through 4.6 summarize Avista's contracts.

Mid-Columbia Hydroelectric Contracts

During the 1950s and 1960s, Public Utility Districts (PUDs) in central Washington developed hydroelectric projects on the Columbia River. Each plant was large compared to loads served by the PUDs. Long-term contracts with public, municipal, and investor-owned utilities throughout the Northwest assisted with project financing and ensured a market for the surplus power. The contract terms obligate the PUDs to deliver power to Avista points of interconnection.

Avista originally entered into long-term contracts for the output of four of these projects "at cost." Avista now competes in capacity auctions to retain the rights of these expiring contracts. The Mid-Columbia contracts in Table 4.5 provide energy, capacity and reserve capabilities; in 2019, the contracts provided approximately 225 MW of capacity and 142 aMW of energy.

[7] Avista is reviewing its policies and may restrict the CT's use when the pipeline is at lower pressures then the current standard. This change could further reduce the plant from producing power in winter months.

The timing of the power received from the Mid-Columbia projects is a result of agreements including the 1961 Columbia River Treaty and the 1964 Pacific Northwest Coordination Agreement (PNCA). Both agreements optimize hydroelectric project operations in the Northwest U.S. and Canada. In return for these benefits, Canada receives return energy under the Canadian Entitlement. The Columbia River Treaty and the PNCA manage storage water in upstream reservoirs for coordinated flood control and power generation optimization. The Columbia River Treaty may end on September 16, 2024. Studies are underway by U.S. and Canadian entities to determine possible post-2024 Columbia River operations. Federal agencies are soliciting feedback from stakeholders and ongoing negotiations will determine the future of the treaty. This IRP does not model alternative outcomes for the treaty negotiations, because it will not likely affect long-term resource acquisitions and we cannot speculate on future wholesale electricity market impacts of the treaty at this time.

Table 4.5: Mid-Columbia Capacity and Energy Contracts[8]

Counter Party	Project(s)	Percent Share (%)	Start Date	End Date	Estimated On-Peak Capability (MW)	Annual Energy (aMW)
Grant PUD	Priest Rapids	3.79	Dec-2001	Dec-2052	36	19.5
Grant PUD	Wanapum	3.79	Dec-2001	Dec-2052	39	18.5
Chelan PUD	Rocky Reach	5.0	Jan-2016	Dec-2030	56	35.9
Chelan PUD	Rock Island	5.0	Jan- 2016	Dec-2030	25	19.0
Douglas PUD	Wells	12.46[9]	Oct- 2018	Dec-2023	79	54.7
Canadian Entitlement					-10	-5.6
2020 Total Net Contracted Capacity and Energy					**225**	**142.0**

Public Utility Regulatory Policies Act (PURPA)

The passage of PURPA by Congress in 1978 required utilities to purchase power from resources meeting certain size and fuel criteria. Avista has many PURPA contracts, as shown in Table 4.6. The IRP assumes renewal of these contracts after their current terms end. Appendix C includes operating details of these projects. Avista takes the energy as produced and does not control the output of any PURPA resources.

[8] For purposes of long-term transmission reservation planning for bundled retail service to native load customers, replacement resources for each of the resources identified in Table 4.5 are presumed and planned to be integrated via Avista's interconnection(s) to the Mid-Columbia region.

[9] Percent share varies each year depending on Douglas PUD's load growth.

Table 4.6: PURPA Agreements

Contract	Fuel Source	Location	Contract End Date	Size (MW)	5 year Gen. History (aMW)
Meyers Falls	Hydro	Kettle Falls, WA	12/2020	1.30	1.10
Spokane Waste to Energy	Waste	Spokane, WA	12/2022	18.00	13.80
Spokane County Digester	Biomass	Spokane, WA	8/2021	0.26	0.13
Plummer Saw Mill	Wood Waste	Plummer, ID	12/2020	5.80	3.66
Deep Creek	Hydro	Northport, WA	12/2022	0.41	0.01
Clark Fork Hydro	Hydro	Clark Fork, ID	12/2037	0.22	0.13
Upriver Dam[10]	Hydro	Spokane, WA	12/2024	17.60	6.30
Big Sheep Creek Hydro	Hydro	Northport, WA	6/2021	1.40	0.92
Ford Hydro LP	Hydro	Weippe, ID	6/2022	1.41	0.42
John Day Hydro	Hydro	Lucile, ID	9/2022	0.90	0.33
Phillips Ranch	Hydro	Northport, WA	n/a	0.02	0.01
City of Cove	Hydro	Cove, OR	10/2038	0.80	0.38
Clearwater Paper	Biomass	Lewiston, ID	12/2023	90.20	44.98
Total				**138.32**	**72.16**

Lancaster Power Purchase Agreement

Avista acquired output rights to the Lancaster CCCT, located in Rathdrum, Idaho, after the sale of Avista Energy in 2007. Lancaster directly interconnects with the Avista transmission system at the BPA Lancaster substation. Under the tolling contract, Avista pays a monthly capacity payment for the sole right to dispatch the plant through October 2026. In addition, Avista pays a variable energy charge and arranges for all of the fuel needs of the plant.

Palouse Wind Power Purchase Agreement

Avista signed a 30-year PPA in 2011 with Palouse Wind for the entire output of its 105 MW project. Avista has the option to purchase the project after 10 years. Commercial operation began in December 2012. The project is EIA-qualified and directly connected to Avista's transmission system between Rosalia and Oaksdale, Washington in Whitman County.

Rattlesnake Flats Wind Power Purchase Agreement

Between the 2017 IRP and this IRP process, Avista identified an opportunity to procure low cost renewable PPA at prices close to the energy market. This opportunity maintains Avista's lower power costs and assists in meeting CETA requirements and corporate clean energy goals. Avista released an RFP for 50 aMW in 2018. The project selected from this process was a 20-year PPA for the 146 MW Rattlesnake Flat wind project with an expected net output of 434,500 MWh (49.6 aMW) each year. The project

[10] Energy estimate is net of the city of Spokane's pumping load.

schedule is to be online in the second half of 2020, and it is located east of Lind, Washington in Adams County.

Adams-Nielson Solar Power Purchase Agreement

Avista signed a 20-year PPA for Washington State's largest commercial solar project in 2017. The project is an 80,000 panel single axis solar facility capable of delivering 19.2 MW of AC power. The project is north of Lind, Washington in Adams County. The project began generating in December 2018. The project serves for Avista's Solar Select program. Solar Select allows commercial customers to purchase the solar energy attributes from the project at no additional cost through a combination of tax incentives from the State of Washington and offsetting power supply expenses.

Table 4.7: Other Contractual Rights and Obligations

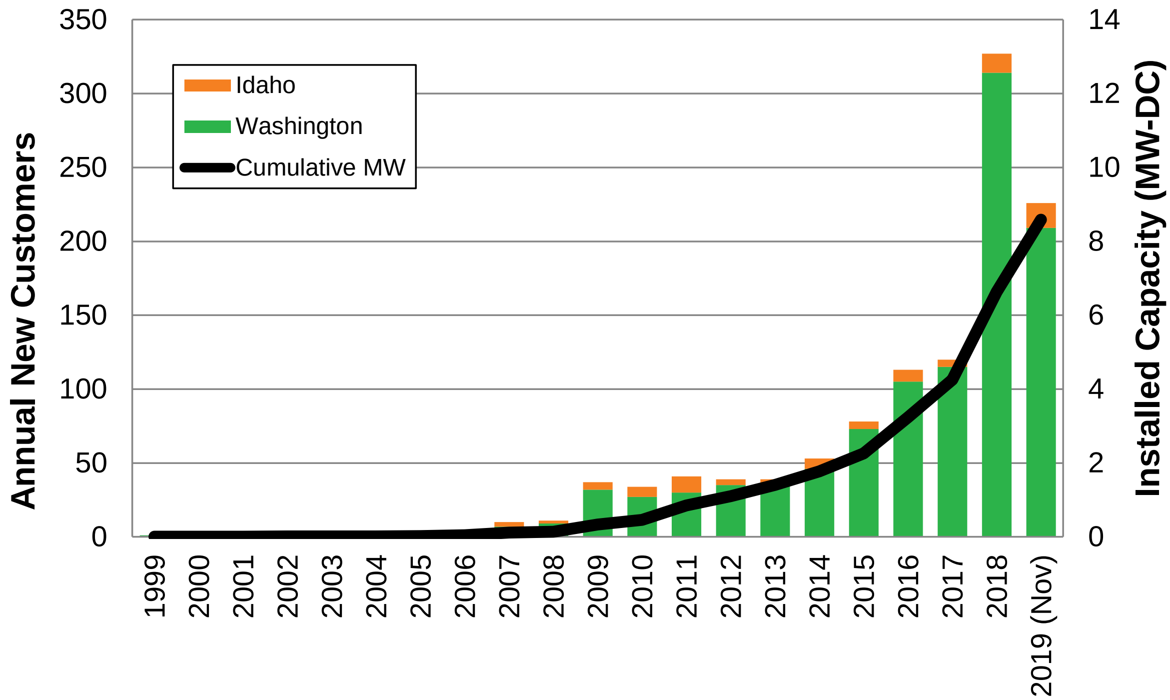
Contract	Type	Fuel Source	End Date	Winter Capacity Contri-bution (MW)	Summer Capacity Contri-bution (MW)	Annual Energy (aMW)
Lancaster	Purchase	Natural Gas	2026	283	233	218
Palouse Wind	Purchase	Wind	2042	5.3	5.3	36.2
Rattlesnake Flats	Purchase	Wind	2040	7.3	7.3	49.6
Adam-Nielson	Purchase	Solar	2038	0.4	10.2	5.6
Nichols Pumping	Sale	System	2023[11]	-5	-5	-5.0
Morgan Stanley	Sale	Clearwater Paper	2023	-46	-46	-44.9
Douglas PUD	Sale	System	2023	-48	-48	-48.0
Total				**416**	**284**	**352**

Customer-Owned Generation

Avista has 1,140 customer-installed net-metered generation projects on its system as of the end of November 2019, representing a total installed capacity of 8.6 MW-DC. Ninety-two percent of installations are in Washington, with most located in Spokane County. Figure 4.3 shows annual net metering customer additions. Solar is the primary net metered technology; the remaining is a mix of wind, combined solar and wind systems, and biogas. The average system size is 7.5 kilowatts. Avista has seen a drop in solar system installs in 2019 due to reduced subsidy rates in Washington. In Idaho, solar install rates continue to increase each year without a major subsidy, but total only 94 as compared to Washington with over 1,000. If the number of net-metering customers continues to increase, Avista may need to adjust rate structures for customers who rely on the utility's infrastructure but do not contribute financially for infrastructure costs.

[11] This obligation operates pumping loads in Colstrip. The end date reflects the energy sold to other Colstrip participants, Avista's obligation is approximately one megawatt and will end when Avista exits the plant.

Figure 4.3: Avista's Net Metering Customers



Natural Gas Pipeline Rights

Avista uses the GTN pipeline owned by TC Energy (formally TransCanada) to transport natural gas to our natural gas-fired generators. This pipeline runs between Alberta, Canada and the California/Oregon border at Malin. Avista's rights on the system are for 60,592 dekatherms per day between the AECO area and Stanfield and another 26,388 dekatherms per day between Malin and Stanfield. This total is 60,592 dekatherms of rights per day. Figure 4.4 illustrates Avista's natural gas pipeline rights. Also included in this figure is the theoretical capacity if the plant runs at full capacity for the entire 24 hours in a day on the system. The maximum burn by Avista is 131,760 dekatherms in one day of the top five historical natural gas burn days, as shown in Table 4.8.

Avista is short on natural gas capacity and uses the short-term transportation market to relieve the shortfall on a day-to-day basis. Historically, these rights were available because the GTN pipeline was not fully subscribed. Recently, natural gas producers have purchased all of the remaining rights on the system to transport their supply south and take advantage of higher prices in the U.S. compared to Canada. Avista plans to continue to acquire its remaining natural gas through the daily market. If this market begins to tighten, Avista will need to invest in onsite fuel storage.

Figure 4.4: Avista's Natural Gas Pipeline Rights

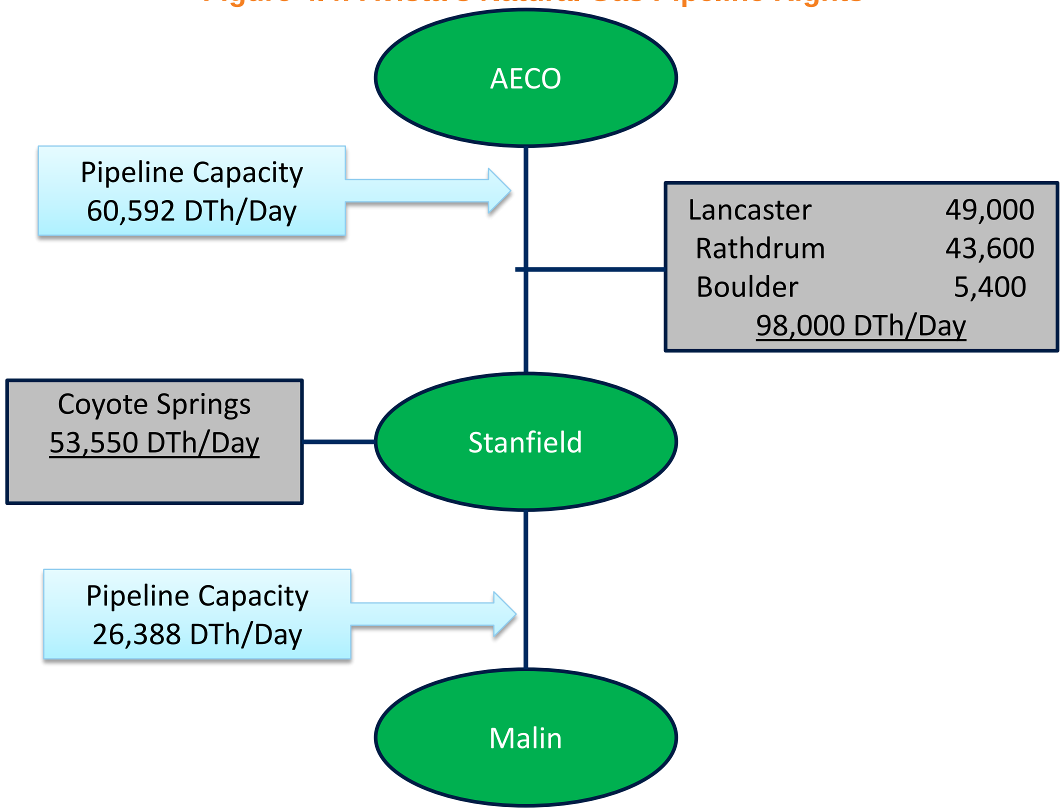


Table 4.8: Top five Historical Peak Natural Gas Usage (Dekatherms)

Date	Boulder Park	Coyote Springs 2	Lancaster	Rathdrum	GTN Total Burn	Current Rights	Shortfall
8/9/2018	5,387	47,668	40,364	38,340	131,760	60,592	(71,168)
7/22/2018	5,452	47,057	43,909	35,016	131,434	60,592	(70,842)
8/8/2018	5,289	47,571	40,841	36,499	130,199	60,592	(69,607)
7/25/2018	3,991	48,201	43,050	34,348	129,591	60,592	(68,999)
8/13/2018	5,352	48,458	40,094	35,491	129,395	60,592	(68,803)

Resource Environmental Requirements and Issues

The generation of electricity has environmental impacts and is subject to regulation by federal, state, and local authorities. The generation, transmission, distribution, service, and storage facilities in which we have ownership interests are designed, operated, and monitored to maintain compliance with applicable environmental laws. Furthermore, Avista conducts periodic reviews and audits of our facilities and operations to ensure compliance. To respond to or anticipate emerging environmental issues, Avista monitors legislative and regulatory developments at all levels of government for environmental issues, particularly those with the potential to impact the operation and productivity of our generating plants and other assets.

Generally, environmental laws and regulations may:

- Increase operating costs of generation;
- Increase the time and costs to build new generation;
- Require modifications to existing plants;
- Require curtailment or shut down of generation;
- Reduce the amount of generation available from plants;
- Restrict the types of plants that can be built or contracted with;
- Require construction of specific types of generation at higher cost; and
- Increase the cost to transport and distribute natural gas.

The following in sections describe applicable regulations in more detail.

Clean Air Act (CAA)

The CAA is a federal law setting requirements for thermal generating plants. States are typically authorized to implement CAA permitting and enforcement. States have adopted parallel laws and regulations to implement the CAA. Some aspects of CAA implementation are delegated to local air authorities. Colstrip, Coyote Springs 2, Kettle Falls, and Rathdrum CT all require CAA Title V operating permits. Boulder Park, Northeast CT, and other operations require minor source permits or simple source registration permits to operate. These requirements can change as the CAA or other regulations change and agencies issue new permits. A number of specific regulatory programs authorized under the CAA can impact Avista's generation, as reflected in the following sections.

Hazardous Air Pollutants (HAPs)

On April 16, 2016, the Mercury Air Toxic Standards (MATS), an EPA rule under the CAA for coal and oil-fired sources, became effective for all Colstrip units. Colstrip performs quarterly compliance assurance stack testing to meet the MATS site-wide limitation for Particulate Matter (PM) emissions (0.03 lbs./MMBtu) a measure used as a surrogate for all HAPs.

In December 2018, the EPA proposed to revise earlier MATS findings and make a new determination that is not "appropriate and necessary" to regulate hazardous air pollutants from power plants. The EPA proposes this conclusion based on a new cost/benefit analysis. Because Colstrip has already implemented applicable MATS control measures, and because changes to the rule are still under review, it is unclear what, if any, impact the EPA's most recent proposal will have.

Montana Mercury Rule

Montana established a site wide Mercury cap in 2010, requiring Mercury to be below 0.9 lbs per Tbtu. Colstrip installed a mercury oxidizer/sorbent injection system. The Montana Department of Environmental Quality (MDEQ) recently reviewed the equipment and concurred with the plant's equipment. Currently Avista's share of units 3 and 4 operate at 0.8 lb per Tbtu range. There is no indication that mercury requirements will change in the IRP time horizon.

Regional Haze Program

EPA set a national goal in 1999 to eliminate man-made visibility degradation in national parks and wilderness areas by 2064. Individual states must take actions to make "reasonable progress" through 10-year plans, including application of Best Available Retrofit Technology (BART) requirements. BART is a retrofit program applied to large emission sources, including electric generating units built between 1962 and 1977. In the absence of state programs, EPA may adopt Federal Implementation Plans (FIPs). On September 18, 2012, EPA finalized the Regional Haze FIP for Montana. In November 2012, several groups petitioned the U.S. Court of Appeals for the Ninth Circuit for review of Montana's FIP. The Court vacated portions of the Final Rule and remanded back to EPA for further proceedings on June 9, 2015. MDEQ is in the process of retaking control of the program from EPA after issuing a Regional Haze Program progress plan for Montana in 2017. A combination of LoNOx burners, overfire air, and Smartburn currently control NOx emissions at Colstrip. Regional coal plant shutdowns indicate the NOx emissions are below the glide path. This progress demonstrates reasonable progress; therefore, Avista anticipates no additional NOx pollution controls Colstrip at this time.

Coal Ash Management/Disposal

In 2015, EPA issued a final rule regarding coal combustion residuals (CCRs), also known as coal combustion byproducts or coal ash. The CCR rule has been the subject of ongoing litigation. In August 2018, the D.C. Circuit struck down provisions of the rule. The rule includes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. The Colstrip owners developed a multi-year compliance plan to address the CCR requirements and existing state obligations (expressed largely through a 2012 Administrative Order on Consent (AOC)). These requirements continue despite the 2018 federal court ruling.

In addition, under the AOC, the Colstrip owners must provide financial assurance, primarily in the form of surety bonds, to secure each owner's pro rata share of various anticipated closure and remediation obligations. The amount of financial assurance required may vary due to the uncertainty associated with remediation activities. Please refer to the Colstrip section for additional information on the AOC/CCR related activities.

Particulate Matter (PM) Issues

Particulate Matter (PM) is the term for a mixture of solid particles and liquid droplets found in the air. Some particles, such as dust, dirt, soot, or smoke, are large or dark enough to see with the naked eye. Others are so small they only detectable with an electron microscope. Particle pollution includes:

- PM_{10}: inhalable particles, with diameters that are generally 10 micrometers and smaller; and
- $PM_{2.5}$: fine inhalable particles, with diameters that are generally 2.5 micrometers and smaller.

There are different standards for PM_{10} and $PM_{2.5}$. Limiting the maximum amount of PM to be present in outdoor air protects human health and the environment. The CAA requires EPA to set National Ambient Air Quality Standards (NAAQS) for PM, as one of the six criteria pollutants considered harmful to public health and the environment. The law also requires periodic EPA reviews of the standards to ensure that they provide adequate health and environmental protection and to update standards as necessary.

Avista has ownership and/or operational control for the following thermal electric generating facilities that produce PM: Boulder Park, Colstrip, Coyote Springs 2, Kettle Falls, Lancaster, Northeast and Rathdrum. Table 4.9 shows each of these generating stations, location, status of the surrounding area with NAAQS for $PM_{2.5}$ and PM_{10}, operating permit, and PM pollution controls.

Appropriate agencies issue air quality operating permits. These operating permits require annual compliance certifications and renewal every five years to incorporate any new standards including any updated NAAQS status.

Table 4.9: Avista Owned and Controlled PM Emissions

Thermal Generating Station	$PM_{2.5}$ NAAQS Status	PM_{10} NAAQS Status	Air Operating Permit	PM Pollution Controls
Boulder Park	Attainment	Maintenance	Minor Source	Pipeline Natural Gas
Colstrip	Attainment	Non-Attainment	Major Source Title V OP	Fluidized Bed Wet Scrubber
Coyote Springs 2	Attainment	Attainment	Major Source Title V OP	Pipeline Natural Gas, Air filters
Kettle Falls	Attainment	Attainment	Major Source Title V OP	Multi-clone collector, Electrostatic Precipitator
Lancaster	Attainment	Attainment	Major Source Title V OP	Pipeline Natural Gas, Air filters
Northeast	Attainment	Maintenance	Minor Source	Pipeline Natural Gas, Air filters
Rathdrum	Attainment	Attainment	Major Source Title V OP	Pipeline Natural Gas, Air filters

Threatened and Endangered Species and Wildlife

A number of species of fish in the Northwest are listed as threatened or endangered under the Federal Endangered Species Act (ESA). Efforts to protect these and other species have not significantly affected generation levels at our facilities. Avista is implementing fish protection measures at our hydroelectric project on the Clark Fork River under a comprehensive settlement agreement. The restoration of native salmonid fish, including bull trout, is a key part of the agreement. The result is a collaborative native salmonid restoration program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license.

Various statutory authorities, including the Migratory Bird Treaty Act, have established penalties for the unauthorized take of migratory birds. Some of our facilities can pose risks to a variety of such birds, so we have developed and follow an avian protection plan.

Climate Change - Federal Regulatory Actions

The EPA released the final version of the Affordable Clean Energy (ACE) rule in June 2019 as the replacement for the Clean Power Plan (CPP). EPA's final rule does not contain any final action on the proposed modifications to the new source review (NSR) program that would provide coal-fired power plants more latitude to make efficiency improvements without triggering pre-construction permit requirements. The final ACE rule combines three distinct EPA actions. First, EPA finalizes the repeal of the CPP. Second, the EPA finalizes the ACE rule; which comprises EPA's determination of the Best System of Emissions Reduction (BSER) for existing coal-fired power plants and establishment of the procedures that will govern States' promulgation of standards of performance for existing EGUs within their borders. EPA sets the final BSER as heat rate efficiency improvements (HRI) based on a range of "candidate technologies" to apply to a plant's operating units and requires each State to determine the technologies applicable to each coal-fired unit based on consideration of remaining useful plant life. Lastly, EPA finalizes a number of changes to the implementing regulations for the timing of State plans for this and future section 111(d) rulemakings. With respect to Colstrip, the MDEQ would initiate the BSER evaluation process.

Climate Change - State Legislation and State Regulatory Activities

Washington and Oregon both adopted non-binding targets to reduce greenhouse gas emissions. Both states enacted targets with an expectation of reaching the targets through a combination of renewable energy standards, eventual carbon pricing mechanisms (such as cap and trade regulation or a carbon tax), and assorted "complementary policies." However, neither state mandated specific reductions yet, but have enacted other targets to reduce greenhouse gas emissions. Washington State enacted Senate Bill 5116 or the Clean Energy Transformation Act (CETA). As stated elsewhere in this IRP, the focus of the legislation is to reduce greenhouse gas emissions from specific sectors of the economy through direct regulation. CETA requires utilities to eliminate coal-fired resources from Washington retail rates by the end of 2025, achieve carbon neutrality by 2030 while meeting a minimum 80 percent of load through delivery of renewable or non-emitting resources to customers, and serve all retail load with renewable and non-emitting resources by 2045.

Washington and Oregon apply a greenhouse gas emissions performance standard (EPS) to electric generation facilities used to serve retail loads in their jurisdictions, whether the facilities are located within those respective states or elsewhere. The EPS prevents utilities from constructing or purchasing generation facilities, or entering into power purchase agreements of five years or longer duration to purchase energy produced by plants that, in any case, have emission levels higher than 1,100 CO2e pounds per MWh. The Washington State Department of Commerce reviews the standard every five years. In September 2018, it adopted a new standard of 925 pounds CO2e per MWh.

Energy Independence Act (EIA)

The EIA in Washington requires electric utilities with over 25,000 customers to acquire qualified renewable energy resources and/or renewable energy credits equal to 15 percent of the utility's total retail load in Washington in 2020. The EIA also requires these utilities to meet biennial energy conservation targets beginning in 2012. The renewable energy standard increased from 3 percent in 2012 to 9 percent in 2016 and 15 percent in 2020. Failure to comply with renewable energy and efficiency standards could result in penalties of $50 per MWh or greater assessed against a utility for each MWh it is deficient in meeting a standard. We have met, and will continue to meet, the requirements of the EIA through a variety of renewable energy generating means, including, but not limited to, some combination of hydroelectric upgrades, wind, biomass, and renewable energy credits. Beginning in 2030, if a utility is compliant with CETA, the utility is deemed to meet the requirements of the EIA.

Colstrip

This section provides further details related to Colstrip. Colstrip was a four-unit coal plant in Eastern Montana. Avista is partial owner in Units 3 and 4. A complete list of the ownership shares and sizes of the plant is in Table 4.10. Puget Sound Energy and Talen Energy shut down units 1 and 2 in early 2020. Washington’s CETA prohibits utilities from charging Washington retail customers with coal after 2025. Utilities failing to comply may receive fines for each MWh delivered into the state after 2030. This requirement applies to Avista, Puget Sound Energy, and PacifiCorp. Oregon (SB 1547) requires utilities to stop using coal by 2030, although there are carve outs through 2035. This law affects PacifiCorp and Portland General Electric.

Figure 4.5: Overview of the Colstrip Area

Table 4.10: Colstrip Ownership Shares[12]

	Unit 1	Unit 2	Unit 3	Unit 4	Total
Unit Nameplate Size (MW)	358	358	778	778	2,272
Operating Capacity (MW)	307	307	740	740	2,094
Year On-Line	1975	1976	1984	1986	
Owners					
Avista	0%	0%	15%	15%	11%
Northwestern Energy	0%	0%	0%	30%	11%
PacifiCorp	0%	0%	10%	10%	7%
Portland General Electric	0%	0%	20%	20%	14%
Talen Energy, LLC	50%	50%	30%	0%	25%
Puget Sound Energy	50%	50%	25%	25%	32%

Coal Contract

Colstrip is supplied fuel from the adjacent coal reserves under coal supply and transportation agreements that expired December 2019. Avista, along with four other owners, agreed to a contract extension with Rosebud Mine LLC to continue supplying the plant with coal. The new contract provides coal through December 31, 2025 with options to extend the contract. The specific terms of the agreement are confidential, but the prices and terms are consistent with the prices assumed in this IRP.

[12] Puget Sound Energy announced an agreement on December 10, 2019 that it intends to sell its 185 MW share of Unit 4 to Northwestern Energy for $1 and enter into a PPA for 90 MW for up to five years. The transmission is also being included in the sale for an undisclosed price. Puget Sound Energy will still maintain responsibility for their current share of remediation and decommissioning costs. Northwestern Energy is seeking review of the proposed transaction by the Montana Utilities Commission,

Water and Waste Management

Colstrip uses water from the Yellowstone River for steam production, air pollution scrubbers, and cooling purposes. The water travels through a 29-mile pipeline to Castle Rock Lake to serve as the Surge pond for the plant and as the water supply for the Town of Colstrip. From the Surge pond, water moves to holding tanks as needed throughout the plant site. The water recycles until it is ultimately lost through evaporation, also known as zero-discharge. An example of this reuse is how the plant removes excess water from the scrubber system fly ash, creating a paste product similar to cement. The paste flows to a holding pond while clear water is reused. Similarly, the bottom ash flows to a holding pond, where it is dewatered and the water reused.

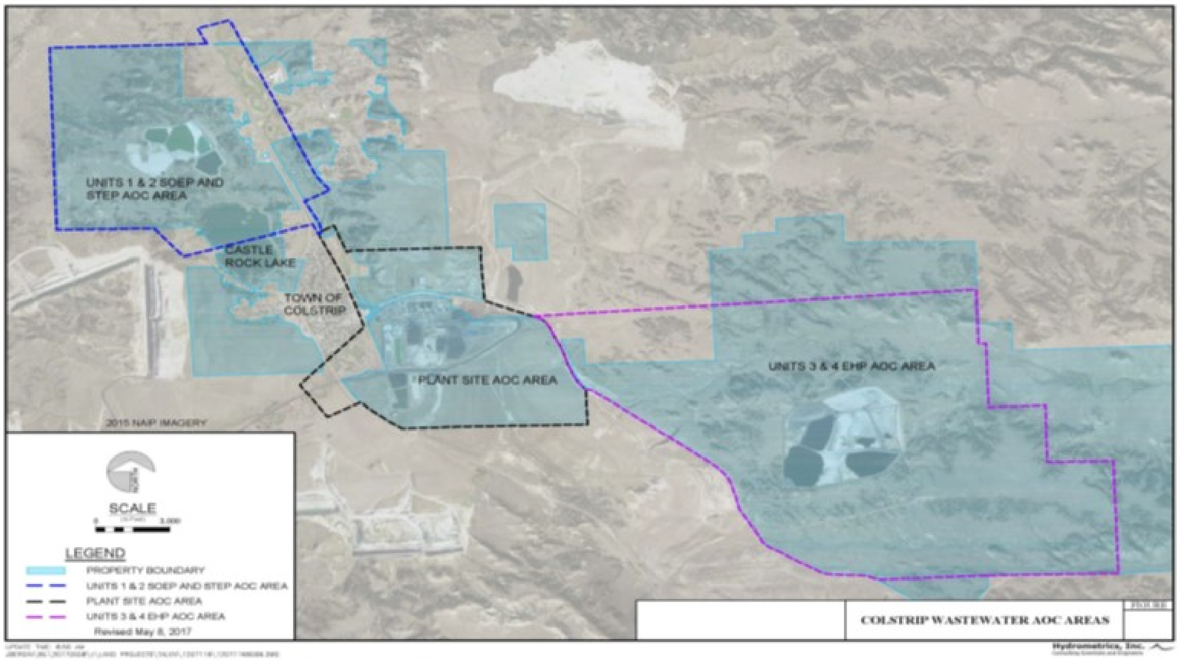
The plant uses three major areas for water and waste management. The first is the Plant Site Area, in which all units share use of the ponds, Avista is responsible for its share of these facilities. The second major area only for Units 3 and 4 is the Effluent Holding Pond (EHP) Area. This area is 2.5 miles to the south east of the plant site. Avista is responsible for its proportional share of the EHP Area. The third storage area is the Stage One Effluent Pond (SOEP)/Stage Two Effluent Pond (STEP); these ponds dispose fly ash from the scrubber slurry/paste from Units 1 and 2. These ponds are nearly two miles to the northwest of the plant. Avista does not have ownership or responsibility in this area. Figure 4.6 shows a map of the different storage areas at Colstrip.

Colstrip will covert to dry ash storage by the end of 2022. The master plan for site wide ash management is filed with the MDEQ-AOC[13] and additional information regarding the CCRs is available at Talen's website[14]. This plan includes removing Boron, Chloride, and Sulfate from groundwater, closure of the existing ash storage ponds, and installation of a new water treatment system along with a dry ash storage facility. Each of the new facilities are required, regardless of the length of the plant's continuing operations. Avista previously posted bonds for $5,841,000 on December 21, 2018 for cost assurance and an additional $383,713 on February 1, 2019 for the closure plan. Avista posted an additional $6,793,050 on February 1, 2019 related to Units 3 and 4 for closure. These amounts are expected to be updated annually, increasing as clean-up plans are approved in the coming years and then decreasing over time as remediation activities are completed.

[13] http://deq.mt.gov/DEQAdmin/mfs/ColstripSteamElectricStation.

[14] https://www.talenenergy.com/ccr-colstrip/.

Figure 4.6: Map of Water Storage



Colstrip Cost for IRP Modeling

Avista provides many of the costs of Avista's share of Colstrip in Table 4.11. These costs are the assumptions included in the plan and are subject to change. Scenarios regarding extending Colstrip operations beyond 2027 use these estimates as a starting point. Avista is not including costs related to the fuel or variable O&M costs due to its sensitive market information regarding how the plant is dispatched. The cost included are the ongoing operations of the plant and the amortization of the existing and future capital expenditures. The CCR costs will extend to 2045. Avista anticipates a sharing ratio of 65 percent of these costs to be recovered by Washington and 35 percent by Idaho.

Table 4.10: Colstrip Costs Modelled in the IRP (millions)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Fixed O&M	10.3	9.4	9.7	10.1	11.2					
CCR- O&M	0.4	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Existing Capital Rev. Req. (WA)	12.1	11.3	10.5	9.8	9.1	0.4				
Existing Capital Rev. Req. (ID)	5.9	5.5	5.1	4.8	4.5	4.2	3.9	0.2		
On-going Capital (expensed)	9.4	3.2	4.2	9.5	6.4					
ARO Capital Rev. Req.	1.7	1.7	1.6	1.6	1.5	1.5	1.4	1.4	1.3	1.3
CCR Master Plan Cap. Rev. Req.	0.5	0.6	0.9	1.1	1.1	1.0	1.0	1.0	0.9	0.9
Total	**40.3**	**32.3**	**32.9**	**37.8**	**34.7**	**8.0**	**7.2**	**3.5**	**3.1**	**3.1**

Post 2025 Considerations

There are three primary drivers affecting operational and financial risks associated with the future viability of the Company's share of Colstrip Units 3 and 4. These include the ownership and operating agreement, the coal contract, and the Washington CETA.

The ability to shut down Colstrip Units 3 and 4 is governed by the ownership and operation agreement. No decisions have been made by the ownership group regarding whether Colstrip Unit 3 and/or Unit 4 will continue to operate after December 31, 2025.

Avista obtains its share of the coal for Colstrip Units 3 and 4 pursuant to a coal supply agreement with Westmoreland Rosebud Mining, LLC. The coal supply agreement expires by its terms on December 31, 2025, but can be extended up to December 31, 2029. If the coal supply agreement is extended beyond December 31, 2025, the parties will need to negotiate a new price for coal for the extended term.

Section 3 of the Washington Clean Energy Transformation Act states: "On or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity."[15] That is, after December 31, 2025, the costs and benefits associated with coal-fired resources (except for decommissioning and remediation costs), including costs and benefits associated with Avista's share of Colstrip Units 3 and 4, cannot be included in Avista's Washington retail electricity rates.[16] Coal-fired resources must be fully depreciated by December 31, 2025.[17]

It is difficult to speculate on all potential scenarios associated with future Colstrip Unit 3 and 4 operations; however, in general, there are three likely scenarios for these units after December 31, 2025:

- one or more of the units will continue to operate with the same ownership;
- one or more of the units will continue to operate, but the ownership in the units will change; and
- the units will be shut down.

If one or both units continue to operate after December 31, 2025, and Avista is an owner of the operating unit or units, there will be certain items that need to be addressed. First, Avista will need to evaluate its contractual obligations under the existing ownership and operation agreement. Second, if Avista is required by contract to provide its share of the coal to operate the unit(s), Avista will need to either extend its existing coal supply agreement or make some other arrangement to obtain its share of the coal. Finally, Avista will need to determine how it is going to comply with the requirements of any applicable laws, including the Washington CETA.

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[15] "Allocation of electricity" means, for the purposes of setting electricity rates, the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity customers that are located in this state.
[16] *See* Clean Energy Transformation Act at Section 2 (defining "electric utility"); Clean Energy Transformation Act at Section 3.
[17] Clean Energy Transformation Act at Section 3.

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5. Energy Efficiency

Avista began offering energy efficiency programs in 1978. These programs are all cost-effective strategies to reduce customer's usage within the prevailing market and economic conditions. Recent programs with the highest impacts on energy savings include residential and non-residential prescriptive lighting, residential fuel efficiency, site-specific lighting, and small business projects. Energy Efficiency programs regularly meet or exceed regional shares of the energy efficiency gains outlined by the Northwest Power and Conservation Council (NPCC).

Section Highlights

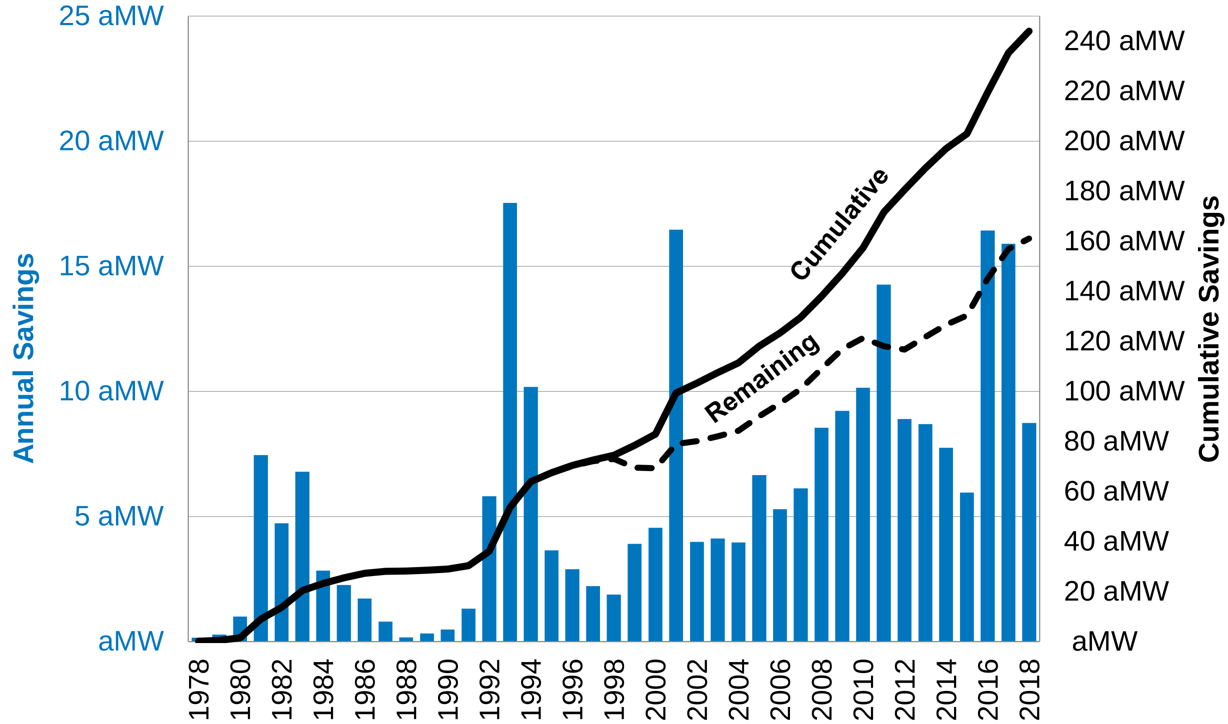
- Current Avista-sponsored energy efficiency reduces loads by nearly 12.2 percent, or 155 aMW.
- This IRP evaluated over 6,300 measure options covering all major end use equipment, as well as devices and actions to reduce energy consumption for this IRP.
- The 2020-21 Washington EIA penalty threshold is 59,948 MWh.

Figure 5.1 illustrates Avista's historical electricity conservation acquisitions. Avista has acquired 240 aMW of energy efficiency since 1978; however, the 18-year average measure life of the conservation portfolio means some measures no longer are reducing load. The 18-year measure life accounts for the difference between the cumulative and online trajectories in Figure 5.1. Currently 155 aMW of energy efficiency serves customers, representing nearly 12.2 percent of 2018 load.

Avista's energy efficiency programs provide energy efficiency and education options to the residential, low income, commercial, and industrial customer segments. Program delivery includes prescriptive, site-specific, regional, upstream, behavioral, market transformation, and third-party direct install options. Prescriptive programs, or standard offerings, provide cash incentives for measures where the customer and equipment are homogenous enough to reasonably qualify eligibility of both and deliver demonstrable savings. An example is the installation of qualifying high-efficiency heating equipment by an eligible customer. Prescriptive programs work in situations where uniform measures or offerings apply to large groups of similar customers and primarily occur in programs for residential and small commercial customers.

Site-specific programs, or customized offerings, provide cash incentives for cost-effective energy saving measures or equipment that are analyzed and contracted and do not meet prescriptive rebate requirements. Site-specific programs require customized services for commercial and industrial customers because of the unique characteristics of each of their premises and processes. Other delivery methods build off these approaches, but may include upstream and mid-stream retail buy-downs of low cost measures, free-to-customer direct install programs, and coordination with regional entities for market transformation efforts. In addition to developing and delivering incentive offerings, Avista provides technical assistance to help educate and inform customers about various types of efficiency measures.

Figure 5.1: Historical Conservation Acquisition (system)



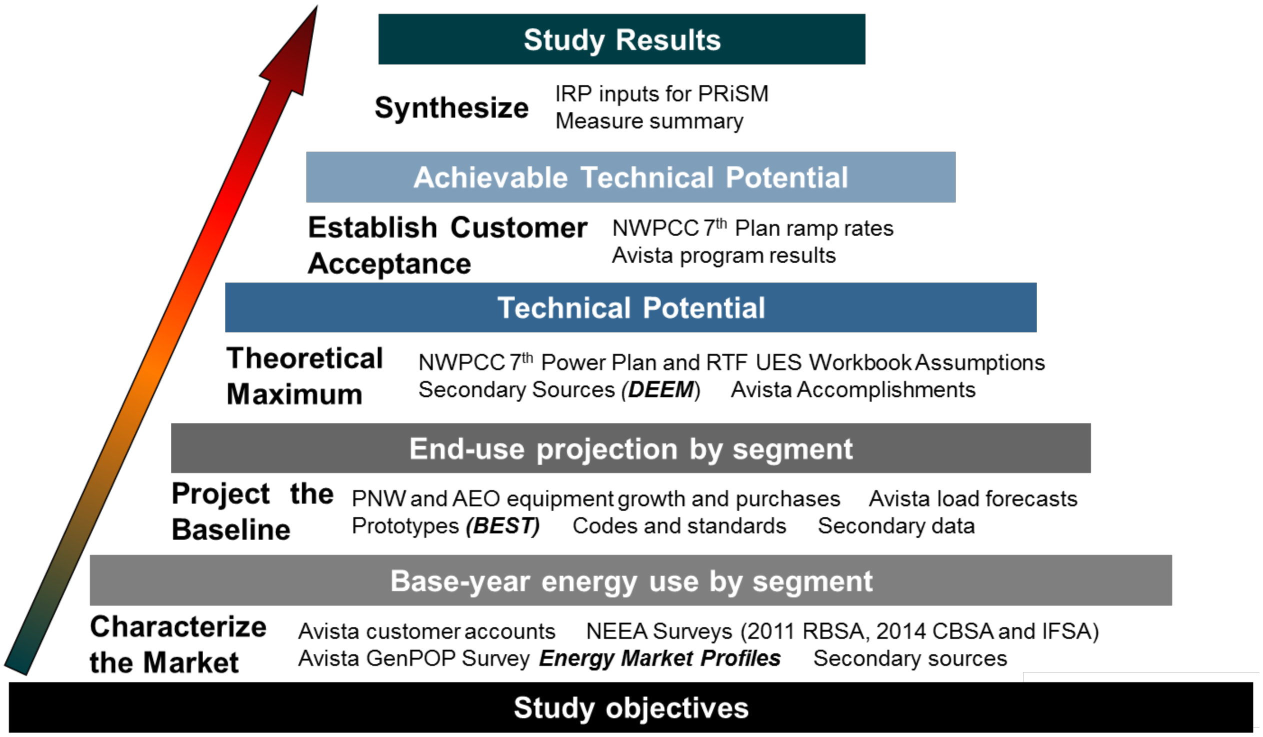
The Conservation Potential Assessment

Avista retained Applied Energy Group (AEG) as an independent third party to assist in developing a Conservation Potential Assessment (CPA) for this IRP. The study forms the basis for the energy efficiency portion of this plan. The CPA identifies the 20-year[1] potential for energy efficiency and provides data on resources specific to Avista's service territory for use in the resource selection process, in accordance with the EIA's energy efficiency goals. The energy efficiency potential considers the impacts of existing programs, the influence of known building codes and standards, technology developments and innovations, changes to the economic influences, and energy prices. The CPA report is in Appendix D of this IRP and the list of measure is in Appendix E.

AEG first developed estimates of *technical potential*, reflecting the adoption of all conservation measures, regardless of cost-effectiveness. The next step identified the *achievable technical potential*; this modifies the technical potential by accounting for customer adoption constraints, using the Council's Seventh Plan ramp rates. The estimated achievable technical potential, along with associated costs, feed into the PRiSM model to select the cost-effective measures. AEG took the following steps to assess and analyze energy efficiency and potential within Avista's service territory. Figure 5.2 illustrates the steps of the analysis.

[1] Avista extrapolates the 20-year data an extra five years for the full planning horizon of this IRP.

Figure 5.2: Analysis Approach Overview



1. **Characterize the Market:** Categorizes energy consumption in the residential (including low-income customers), commercial, and industrial sectors. This assessment uses utility and secondary data to characterize customers' electricity usage behavior in Avista's service territory. AEG uses this assessment to develop energy market profiles describing energy consumption by market segment, vintage (existing or new construction), end use, and technology.
2. **Baseline Projection:** Develops a projection of energy and demand for electricity, absent the effects of future conservation by sector and by end use, for the entire 20-year study.
3. **Measure Assessment:** Identifies and characterizes energy efficiency measures appropriate for Avista, including regional savings from energy efficiency measures acquired through Northwest Energy Efficiency Alliance efforts.
4. **Potential:** Analyzes measures to identify technical and achievable technical conservation potential.

Washington House Bill 1444 Appliance Standards

The CPA incorporates newly enacted legislation for all jurisdictions when the information is available. For this current CPA, Avista adjusted its Washington selections with guidance from House Bill 1444 (HB 1444) which provides minimum efficiency standards for several residential, commercial, and industrial measures. HB 1444 places minimum efficiency standards on general service lamps (LEDs), showerheads, commercial fryers, commercial hot holding cabinets, and several other residential and non-residential appliances.

The structure of Avista's Energy Efficiency program incentivizes customers to install and use high efficiency equipment. The minimum standards outlined in HB 1444 reduce the overall potential for Avista's conservation program since the opportunity for incentivizing customers would not result in participating in higher efficiency products since the high efficiency would be the only option. Including HB 1444 in Avista's CPA reduces the overall potential for the state of Washington by 0.5 percent (32,000 MWh) through 2030 and 0.7 percent (43,000 MWh) by 2040. These minimum efficiency standards did not affect Idaho's service territory's potential or energy efficiency.

Market Segmentation

The CPA divides Avista customers by state and by class. The residential class segments include single-family, multi-family, manufactured home, and low-income customers.[2] AEG incorporated information from the Commercial Building Stock Assessment to break out the commercial sector by building type. Avista analyzed the industrial sector as a whole for each state. AEG characterized energy use by end use within each segment in each sector, including space heating, cooling, lighting, water heat or motors; and by technology, including heat pump and resistance-electric space heating.

The baseline projection is the "business as usual" metric without future utility conservation programs. It estimates annual electricity consumption and peak demand by customer segment and end use absent future efficiency programs. The baseline projection includes the impacts of known building codes and energy efficiency standards as of 2018 when the study began. Codes and standards have direct bearing on the amount of energy efficiency potential existing beyond the impact of these efforts. The baseline projection accounts for market changes including:

- customer and market growth;
- income growth;
- retail rates forecasts;
- trends in end use and technology saturations;
- equipment purchase decisions;
- consumer price elasticity;
- income; and
- persons per household.

For each customer class, AEG compiled a list of electrical energy efficiency measures and equipment, drawing from the NPCC's Seventh Power Plan, the Regional Technical Forum, and other measures applicable to Avista. The 6,400 individual measures included in the CPA represent a wide variety of end use applications, as well as devices and actions able to reduce customer energy consumption. The AEG study includes measure costs, energy and capacity savings, and estimated useful life.
Avista, through its PRiSM model, considers other performance factors for the list of measures and performs an economic screening on each measure for every year of the study to develop the economic potential of Avista's service territory.

[2] The low-income threshold for this study is 200 percent of the federal poverty level. Low-income information is available from census data and the American Community Survey data.

Avista supplements energy efficiency activities by including potentials for distribution efficiency measures consistent with EIA conservation targets and the NPCC Seventh Power Plan.

Avista manages street light fixtures for many local and state governments. As an element of its 2013 Street Light Asset Management Plan, Avista's Asset Management group replaced approximately 21,640 high-pressure sodium fixtures, of which 15,148 are in Washington, with comparable LED fixtures. This project began in in 2015, with the vast majority of lights replaced by the end of 2019. For 2020-2021, it is expected that a small number of outstanding lights will be converted, resulting in distribution efficiencies of 136 MWh in both 2020 and 2021.

Grid Modernization technology has been designed to improve the power grid's reliability and performance by optimizing the push and pull from supply and demand. Ultimately, these projects will move the region and nation closer to establishing a more efficient and effective electricity infrastructure that's expected to help contain costs, reduce emissions, incorporate more wind power and other types of renewable energy, increase power grid reliability, and provide greater flexibility for consumers. The total estimated savings from feeder upgrades is 269 MWh in 2020 and 152 MWh is 2021.

Overview of Energy Efficiency Potential

AEG's approach adhered to the conventions outlined in the National Action Plan for Energy Efficiency Guide for Conducting Potential Studies.[3] The guide represents the most credible and comprehensive national industry standard practice for specifying energy efficiency potential. Specifically, two types of potential are in this study, as discussed below. Table 5.1 shows the CPA results for technical and achievable technical potential.

Table 5.1: Cumulative Potential Savings (Across All Sectors for Selected Years)

	2021	2022	2025	2030	2040
Technical Potential (GWh)	170.0	331.7	800.5	1,522.7	2,502.1
Washington (GWh)	116.4	224.9	531.4	996.7	1,620.5
Idaho (GWh)	53.6	106.8	269.1	526.0	881.6
Total Technical Potential (aMW)	19.4	37.9	91.4	173.8	285.6
Technical Achievable Potential (GWh)	85.3	173.9	469.0	1,020.3	2,062.3
Washington (GWh)	59.6	119.2	309.2	660.2	1,318.9
Idaho (GWh)	25.7	54.7	159.8	360.2	743.4
Total Technical Achievable Savings (aMW)	9.7	19.9	53.5	116.5	235.4

Technical Potential

Technical potential finds the most energy-efficient option commercially available for each purchase decision, regardless of its cost. This theoretical case provides the broadest and highest definition of savings potential because it quantifies savings resulting if all current equipment, processes, and practices, in all market sectors, were

[3] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025:* Developing a Framework for Change. www.epa.gov/eeactionplan

replaced by the most efficient and feasible technology. Technical potential in the CPA is a “phased-in technical potential,” meaning only the portion of current equipment stock at the end of its useful life is considered and changed out with the most efficient measures available. Non-equipment measures, such as controls and other devices (e.g., programmable thermostats) will phase-in over time, just like the equipment measures.

Technical Achievable Potential

Technical achievable potential is a subset of technical potential and represents the portion comprised of technically feasible reductions in load associated with applicable end-uses. It refines technical potential by applying customer participation rates to account for market barriers, customer awareness and attitudes, program maturity, and other factors that may affect market penetration of energy efficiency measures. The customer participation rates use the NPCC Seventh Power Plan ramp rates.

PRiSM Co-Optimization

Avista’s identifies achievable economic conservation potential by concurrently evaluating supply-side and demand-side resources together in Avista’s PRiSM model. In PRiSM, the energy efficiency resources compete with supply-side and demand response options to meet Avista resource deficits; although, energy efficiency measures benefit by receiving additional value streams as compared to other resources. These additional value streams include 10 percent more energy and capacity benefits as compared to the supply-side resources. Energy efficiency also receives additional financial benefits by including financial savings from reducing line losses and avoided transmission and distribution costs. In Washington, an additional credit for reducing greenhouse gas emissions is also included.

Energy Efficiency Targets

Energy efficiency will lower system sales by an additional 138 aMW by 2040; this translates into a 12.6 percent savings. The savings between states are similar to the share of load between states, as Idaho saves 37 percent of the saving potential as compared to Washington’s 63 percent. Figure 5.3 shows the total savings by state for selected years. Commercial and Residential customers provide a majority of the savings of the three major customer classes. Each of these savings are broken-down between the states in Figure 5.4 and Figure 5.5.

Figure 5.3: Conservation Potential Assessment - 20-Year Cumulative MWh

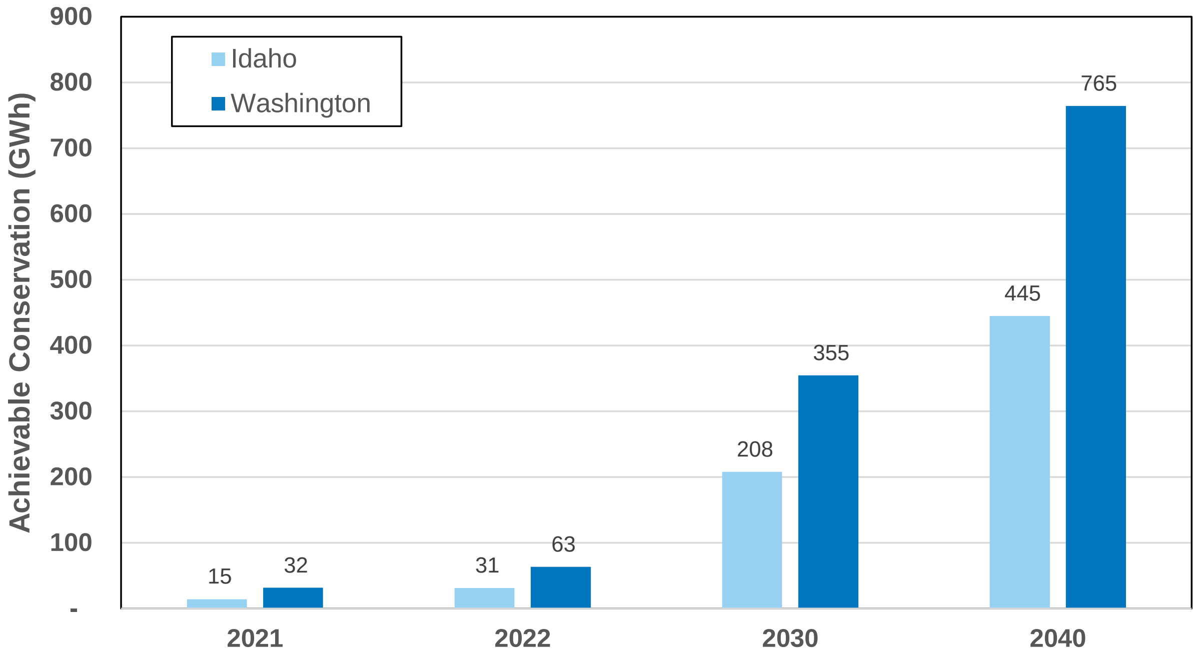
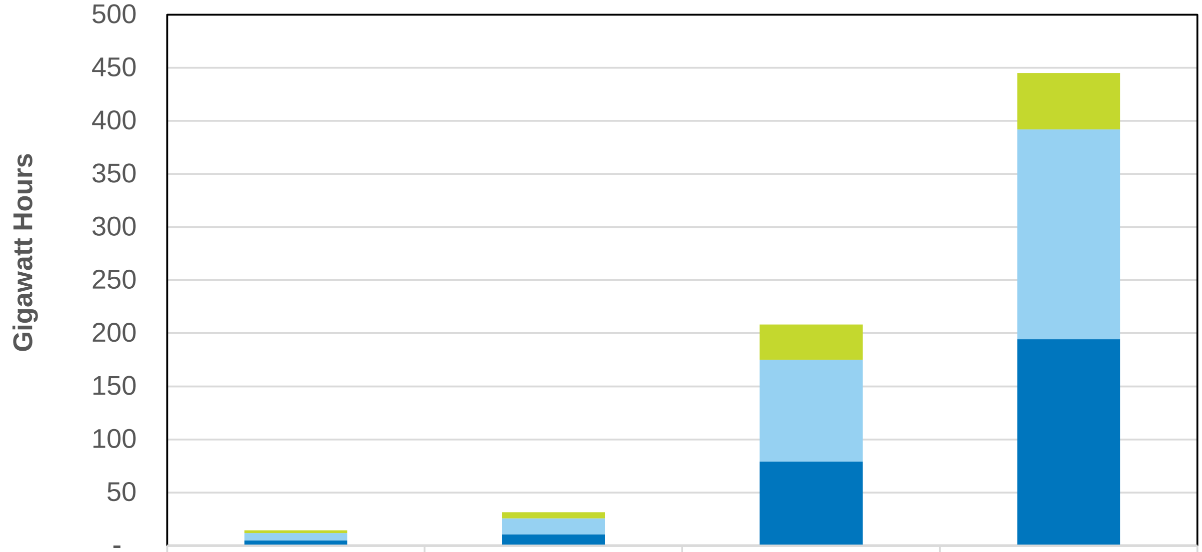
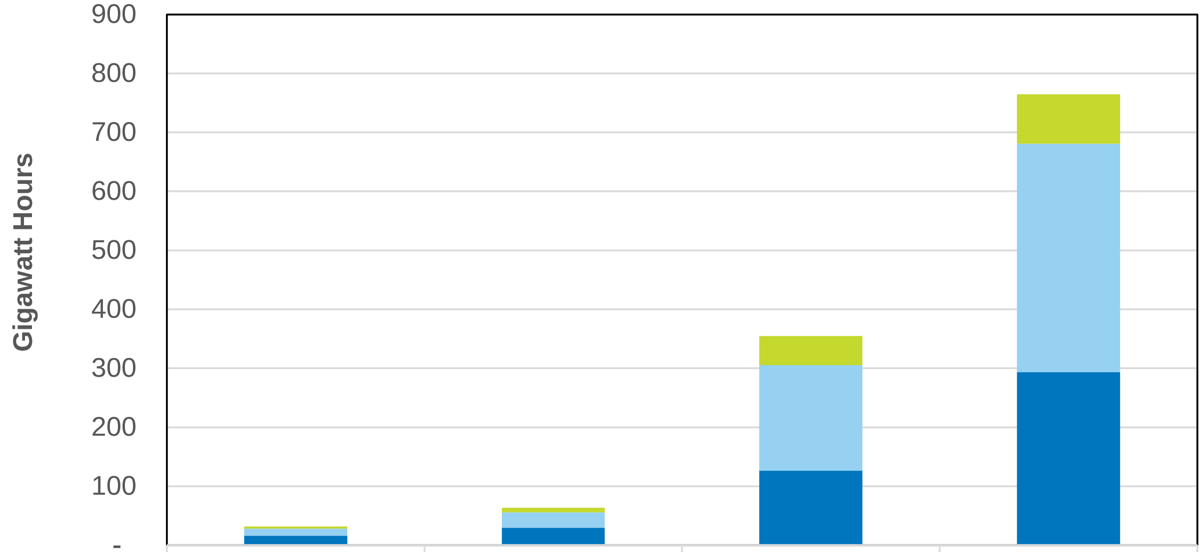


Figure 5.4: Idaho Energy Efficiency Savings by Segment



	2021	2022	2030	2040
Industrial	3	6	33	53
Commercial	7	15	96	198
Residential	5	10	79	194

Figure 5.5: Washington Energy Efficiency Savings by Segment



	2021	2022	2030	2040
Industrial	4	8	50	84
Commercial	12	26	179	388
Residential	16	30	127	293

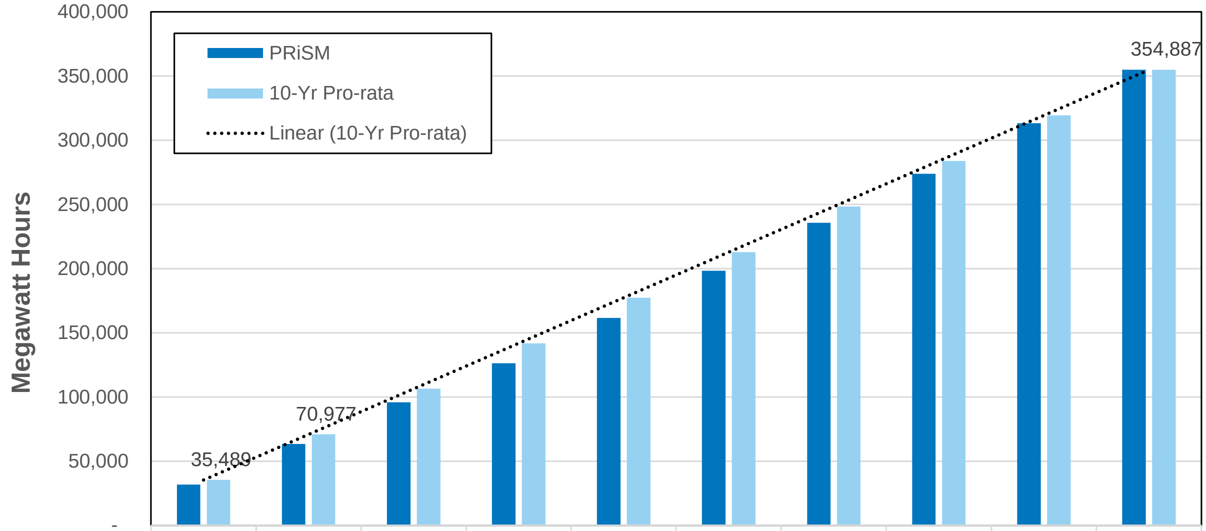
Washington Biennial Conservation Plan

The IRP process provides the energy efficiency targets for Washington's EIA Biennial Conservation Plan. Pursuant to requirements in Washington, the biennial conservation target must be no lower than a pro rata share of the utility's ten-year conservation potential. In setting the Company's target, both the two-year achievable potential and the ten-year pro rata savings are determined with the higher value used to inform the EIA Biennial target. Figure 5.6 shows the annual selection of new energy efficiency as compared to the 10-year pro-rata share methodology.

For the 2020-2021 CPA, the two-year achievable potential is 63,450 MWh for Washington electric operations. The pro-rata share of the utility's ten-year conservation potential is 70,977 MWh and therefore used in the calculation of the biennial target. Table 5.2 contains achievable conservation potential for 2020-2021 using the PRiSM methodology.

Also included is the energy savings expected from the 2020 and 2021 feeder upgrade projects. See Chapter 8 – Transmission and Distribution Planning for more information. The target also includes the efforts from Avista's streetlight program, which should achieve 272 MWh of savings between 2020 and 2021.

Figure 5.6: Washington Annual Achievable Potential Energy Efficiency (Megawatt Hours)



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PRiSM	31,769	63,450	95,953	126,401	161,602	198,365	235,673	273,843	313,230	354,887
10-Yr Pro-rata	35,489	70,977	106,466	141,955	177,443	212,932	248,421	283,909	319,398	354,887

Table 5.2: Biennial Conservation Target for Washington Energy Efficiency

2020-2021 Biennial Conservation Target (MWh)	
CPA Pro-Rata Share	70,977
Distribution and Street Light Efficiency	504
EIA Target	**71,481**
Decoupling Threshold	3,574
Total Utility Conservation Goal	**75,055**
Excluded Programs (NEEA)	-12,896
Utility Specific Conservation Goal	**62,159**
Decoupling Threshold	-3,574
EIA Penalty Threshold	**58,585**

Table 5.3: Annual Achievable Potential Energy Efficiency (Megawatt Hours)

Year	Methodology	Washington	Idaho	Total
2020	Feeder Upgrades	269	0	269
2021	Feeder Upgrades	152	0	152
2020	LED Street Lighting	41	95	136
2021	LED Street Lighting	41	95	136

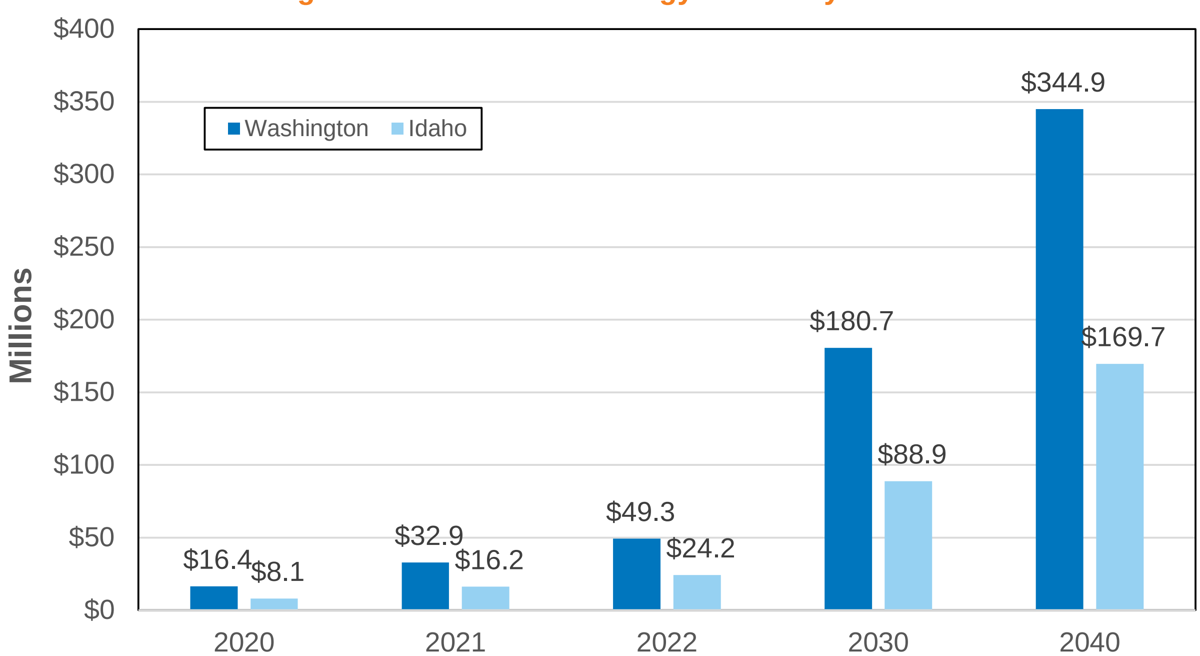
Energy Efficiency Related Financial Impacts

The Washington EIA requires utilities with over 25,000 customers acquire all cost-effective and achievable energy conservation.[4] For the first 24-month period under the law, 2010-2011, this equaled a ramped-in share of the regional 10-year conservation target identified in the Seventh Power Plan. Penalties of at least $50 per MWh exist for utilities not achieving Washington EIA targets.

The EIA requirement to acquire all cost-effective and achievable conservation may pose significant financial implications for Washington customers. Based on CPA results, the projected 2020 conservation acquisition cost to electric customers is approximately $16.4 million. This amount grows to $32.9 million by 2021 and a total of $180.7 million over this 10-year period. Costs continue increasing after 2030 to over $344 million in 2040. Figure 5.7 shows the annual cost in millions of nominal dollars for the utility to acquire the projected electric achievable potential. In total, the levelized price for Washington's savings is 3.5 cents per kWh.

For Idaho, Avista continues to pursue all cost-effective and achievable energy efficiency. Based on CPA results, the projected 2021 Idaho conservation acquisition cost to electric customers is approximately $8 million. This amount grows to $16 million by 2021 and a total of $88.9 million over this 10-year period. Costs continue increasing after 2030 to more than $169.7 million in 2040. Table 5.7 shows the annual cost in millions of nominal dollars for the utility to acquire the projected electric achievable potential. In total, the levelized price for Idaho's savings is 3.4 cents per kWh.

Figure 5.7: Cumulative Energy Efficiency Costs



[4] The EIA defines cost effective as 10 percent higher than the cost a utility would otherwise spend on energy acquisition.

Integrating Results into Business Planning and Operations

The CPA and IRP energy efficiency evaluation processes provide high-level estimates of conservation cost-effectiveness and acquisition opportunities. Results establish baseline goals for continued development and enhancement of energy efficiency programs, but the results are not detailed enough to form an actionable acquisition plan. Avista uses both processes' results to establish a budget for energy efficiency measures, help determine the size and skill sets necessary for future operations, and identify general target markets for energy efficiency programs. This section provides an overview of recent operations of the individual sectors, as well as energy efficiency business planning.

The CPA is useful for implementing energy efficiency programs in the following ways:

- Identifying conservation resource potentials by sector, segment, end use, and measure of where energy savings may come from. Energy efficiency staff uses CPA results to determine the segments and end uses/measures to target.
- Identifying measures with the highest total resource cost or TRC (in Washington) and utility cost test or UCT (in Idaho) benefit-cost ratios, resulting in the lowest cost resources, brings the greatest amount of benefits to the overall portfolio.
- By identifying measures with great adoption barriers based on the economic versus achievable results by measure, staff can develop effective programs for measures with slow adoption or significant barriers.
- By improving the design of current program offerings, staff can review the measure level results by sector and compare the savings with the largest-saving measures currently offered. This analysis may lead to the addition or elimination of programs. Additional consideration for lost opportunities can lead to offering greater incentives on measures with higher benefits and lower incentives on measures with lower benefits.

The CPA illustrates potential markets and provides a list of cost-effective measures to analyze through the ongoing energy efficiency business planning process. This review of both residential and non-residential program concepts, and their sensitivity to more detailed assumptions, feeds into program planning.

Residential Sector Overview

The Company's residential portfolio uses several approaches to engage and encourage customers to consider energy efficiency improvements within their home. Prescriptive rebate programs are the main component of the portfolio, but augment a variety of other interventions. These include upstream buy-down of low-cost measures (e.g. lighting and water saving measures) as well as white goods where this approach is more efficient than processing individual rebates. Other efforts include select distribution of low-cost lighting and weatherization materials, direct-install programs and a multi-faceted, multichannel outreach and customer engagement.

Residential customers received over $7.3 million in rebates to offset the cost of implementing these energy efficiency measures. All programs within the residential portfolio contributed over 29,766 MWh to the 2018 annual energy savings.

In 2018, Avista moved to full implementation of its Multi-family Direct Install Program providing Avista customers with access to low-cost energy savings measures. The program design allows for the direct installation of these measures at apartments and other multifamily living facilities. Avista added the program to its list of residential offerings to address the hard-to-reach segment, which has historically included tenants in rental agreements and multifamily housing situations. While providing low-cost energy saving measures is a primary driver of the program, it also gives the Company an opportunity to provide energy efficiency education to customers and apartment managers.

Low-Income Sector Overview

The Company leverages the infrastructure of seven network Community Action Program (CAP) agencies and one tribal weatherization organization to deliver energy efficiency programs for the Company's low-income residential customers in Avista's service territory. CAP agencies have resources to income qualify, prioritize and treat clients homes based upon a number of characteristics that are not available to Avista. In addition to the Company's annual funding, the agencies have other monetary resources to leverage when treating a home with weatherization or other energy efficiency measures. The agencies either have in-house or contract crews to install many of the efficiency measures of the program.

Avista's general outreach is a "high touch" customer experience for our most vulnerable customer groups including seniors and those with limited incomes. Each outreach encounter includes information about bill payment options and energy management tips, along with the distribution of low cost weatherization materials. Many events are coordinated each year including Avista sponsored energy fairs and the energy resource van. Avista also partners with community organizations to reach these customers through other means such as area food bank/pantry distribution sites, senior center activities, or affordable housing developments. In 2018, Avista attended 116 events and reached well over 11,000 customers in the Washington service territory along with 67 events and reaching 5,000 customers in the Idaho service territory.

The low-income energy efficiency programs contributed 1,011 MWh of electricity savings and 20,172 therms of natural gas savings in 2018.

Non-Residential Sector Overview

Non-residential energy efficiency programs deliver energy efficiency through a combination of prescriptive and site-specific offerings. Any measure not offered through a prescriptive program is eligible for analysis through the site-specific program, subject to the criteria for program participation. Prescriptive paths for the non-residential market are preferred for small and uniform measures, but larger measures may also fit where customers, equipment, and estimated savings are reasonably homogenous.

In 2018, more than 2,100 prescriptive and site-specific nonresidential projects received funding. Avista contributed over $10.2 million for energy efficiency upgrades in nonresidential applications. Non-residential programs realized over 57,000 MWh and 138,027 therms in annual first-year energy savings.

Conservation's T&D Deferral Analysis

Cost-effective energy efficiency programs require a review of cost versus potential benefits. One benefit is the generation and delivery system investments *avoided* or *deferred*. Generation avoided investments are fairly straightforward, but avoided transmission and distribution (T&D) system components tend to be less straightforward as the investments are lumpy, location specific, and may or may not be reduced by energy efficiency due to the thermal limitations of the system.

The 2017 IRP acknowledgement letter requested that Avista determine whether to move the T&D benefits estimates to a forward-looking value versus a historical value. With many changes occurring in energy efficiency in the future, there is merit in exploring the deferral value on the future use of transmission and distribution systems. A forward-looking T&D deferral value could provide better alignment between the expected use of the Company's system and the valuation of customer benefits. Conversely, estimates on future T&D values can be more difficult to quantify and are subject to many iterations throughout the T&D planning process.

Avista uses a historical approach, also known as the current values approach. It considers the amount of current investment in both T&D from a revenue requirement reference point, then divides by the peak load of the system, to estimate a $/kW-yr. value. This method's strength is its simplicity, lending itself to frequent updates, but it does not accurately portray the amount of deferred future T&D investment due to new conservation programs.

The impact of implementing a forward-looking T&D deferral value would attempt to better align with known future activity; however, data on future T&D investments as they relate to energy efficiency is less reliable as it is not a primary consideration for many T&D projects. A potential impact of a forward-looking methodology is that a component of the conservation avoided cost calculations could be incorrect or inaccurate.

The impact of implementing or continuing a historically-based methodology is the avoided cost included in the Company's CPA does not address future known changes to the T&D system and those benefits would not be reflected in the avoided cost. However, the strength of this approach is that data related to its calculation uses published T&D values.

In an attempt to address the shortcoming of both methodologies, Avista chose to base its T&D deferral on its Cost of Service study with proforma values for plant resources. This adjustment attempts to provide a forward look for future T&D investments based on historic plant amounts. Avista utilizes the most recent Cost of Service study for its net transmission and distribution values as provided in Dockets AVU-E-19-04 for Idaho and UE-190334 for Washington. The strengths of this approach include values that are verifiable, published, and references in the Company's general rate case along with estimates on the values of transmission and distribution assets for future periods.

Table 5.4 below illustrates the transmission and distribution values calculated for the Company's T&D deferred benefits for energy efficiency.

Table 5.4: Transmission and Distribution Benefit

	Transmission Net Book Value	Distribution Net Book Vale
Washington	341,627,000	742,302,000
Idaho	178,117,000	352,752,000
Total	519,744,000	1,095,054,000
Revenue Requirement	519,826,223	1,175,906,417
Peak Load (MW)	1,693	1,693
Current $/kW	306.96	694.38
Levelized Cost	15.95	17.07
Total Levelized cost		33.01

6. Demand Response

Historically, Demand Response (DR) programs provide capacity at times when wholesale prices are unusually high, when a shortfall of generation or transmission occurs, or during an unexpected emergency grid-operations situation. Traditional DR in the form of time-of-use rates, peak time rebates, direct load control programs or bi-lateral agreements allow load reductions to specific enrolled customers during such periods until the load event is over or the customer has met their commitment. More recently, DR driven initiatives are providing reliable ancillary service support in wholesale markets with future expectations of providing additional services to the modern grid.

Section Highlights

- Avista's Demand Response experience dates back to at least 2001.
- Avista contracted AEG to perform a residential and commercial demand response potential assessment for this IRP.
- This IRP studied 17 DR programs, up from four in the last plan.
- Demand Response receives a 40 percent peak credit against peak demand.

Avista's experience with DR dates back at least to the 2001 Energy Crisis. Avista responded with all-customer and irrigation customer buy-back programs and bi-lateral agreements with its largest industrial customers. These programs, along with enhanced commercial and residential energy efficiency programs, reduced the need for purchases in very high-cost wholesale electricity markets. A July 2006 multi-day heat wave again led Avista to request DR through media outlets for customers to conserve energy. We also initiated short-term agreements with large industrial customers to curtail loads. During the 2006 event, Avista estimates DR reduced loads by 50 MW. After the 2006 event, Avista implemented additional short-term bi-lateral agreements for DR with its largest customers for use during grid emergencies.

2007-2009 Residential Demand Response Pilot

The 2006 heat wave event led Avista to conduct a two-year residential load control pilot between 2007 and 2009 to study specific technologies and examine cost-effectiveness and customer acceptance. The pilot tested scalable Direct Load Control (DLC) devices based on installations in approximately 100 volunteer households in Sandpoint and Moscow, Idaho. The sample allowed Avista to test DR with the benefits of a larger-scale project, but in a controlled and customer-friendly manner. Avista installed DLC devices on residential heat pumps, water heaters, electric forced-air furnaces, and air conditioners to control operation during 10 scheduled events at peak times ranging from two-to-four hours each. A separate group, within the same communities, participated in an in-home-display device study as part of the pilot. The program provided Avista and its customers experience with "near-real time" energy-usage feedback equipment. Information gained from the pilot is in the report filed with the Idaho Public Utilities Commission[1].

[1] https://puc.idaho.gov/fileroom/cases/elec/AVU/AVUE0704/company/20100303FINAL%20REPORT.pdf

2009-2014 Smart Grid Demonstration Project

Following the North Idaho DR pilot program, Avista engaged in a DR program as part of the Northwest Regional Smart Grid Demonstration Project (SGDP) with Washington State University (WSU) and approximately 70 residential customers in Pullman and Albion, Washington. Residential customer assets including forced-air electric furnaces, heat pumps, and central air-conditioning units received a Smart Communicating Thermostat provided and installed by Avista. The DLC approach was non-traditional, meaning the DR events were not prescheduled, but rather Avista controlled customer loads with an automated process based on utility or regional grid needs while using predefined customer preferences (no more than a two degree offset for residential customers and an energy management system at WSU with a console operator). More importantly, the technology used in the DR portion of the SGDP predicted if equipment was available for participation in the control event, which provided real time feedback of the actual load reduction due to the DR event. Additionally, WSU facility operators had instantaneous feedback due to the integration between Avista and their building management system. Residential customer notifications of the DR event occurred via their smart thermostat. The SGDP began in 2009 and concluded in 2014. Avista reported information gained from this project to the Project's prime sponsor for use in the SGDP's final project report and compilation with other SGDP initiatives[2].

Experiences from both DLC pilots show participating customer engagement is high; however, recruiting participants is challenging. Avista's service territory has high natural gas penetration level meaning many customers cannot benefit greatly from typical DLC space and water heat programs. Additionally, customers did not seem overly interested in the DLC programs as offered. BPA has found similar challenges in gaining customer interest in their regional DLC programs[3]. A 2019 Avista Quantitative Survey, conducted by the Shelton Group, also found customer interest to participate in DR programs to be low. Avista paid customers direct incentives for program participation in both DLC pilots. Incentive levels were a premium to recruit and retain customers and not intended to be scalable. Avista will need to conduct additional analysis to determine cost effective payment strategies beyond pilots to mass-market DLC programs. Where Avista is not able to harness adequate customer interest at cost-effective incentive levels, the future of DR could be more limited than assumed in this IRP.

Avista will evaluate and consider DR programs to meet future load requirements where cost effective compared to other alternatives and does not adversely influence reliability or customer satisfaction with service. To fulfill this commitment, Avista sponsors DR potential assessment studies to identify the 20-year DR potential specific to Avista's service territory for use in the resource selection process. The first study occurred for the 2015 IRP in response to a 2013 IRP Action Item, and subsequent studies performed for the 2017 and most current IRPs.

[2] https://www.smartgrid.gov/files/OE0000190_Battelle_FinalRep_2015_06.pdf
[3] BPA's partnership with Kootenai Electric Coop, https://www.bpa.gov/EE/Technology/demand-response/Documents/20111211_Final_Evaluation_Report_for_KEC_Peak_Project.pdf

Demand Response Potential Assessment Study

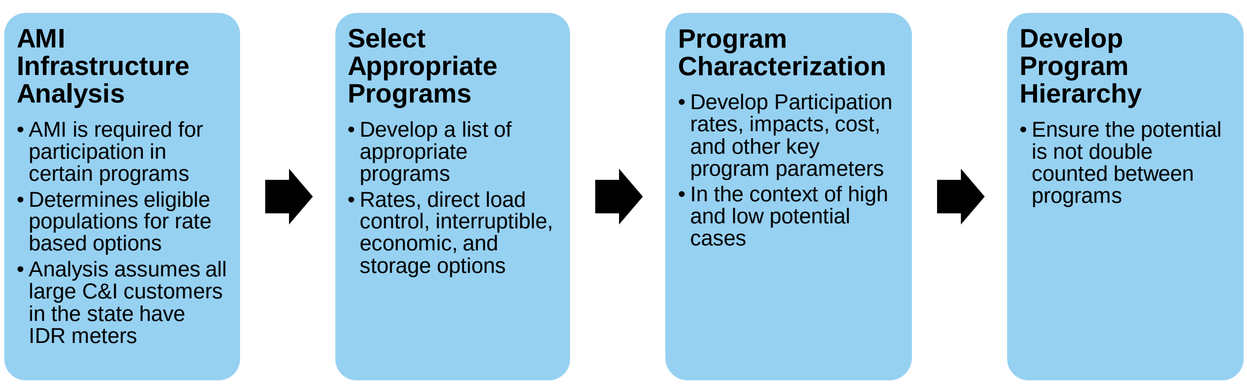
Avista retained AEG to study the potential of DR for all but the irrigation market sector in Avista's service territory for the 20-year planning horizon of 2021–2040[4]. The study primarily sought to develop reliable estimates of the magnitude, timing, and costs of DR resources likely available to Avista for meeting both winter and summer peak loads. The study's focus is on resources assumed achievable during the planning horizon, recognizing known market dynamics may hinder acquisition.

Figure 6.1 outlines AEG's approach to determine potential DR programs in Avista's service territory. Many DR programs require Advanced Metering Infrastructure (AMI) for settlement purposes. All DR pricing programs, behavior and third party contract DR programs included in this study require AMI as an enabling technology. AMI deployment is underway in Washington with completion slated for fall of 2020. AEG broadly assumed that Avista would follow with AMI metering in Idaho and used a three-year ramp rate for full deployment, finishing in 2025.

As with the CPA study for Energy Efficiency, AEG looks at Avista's customer accounts and rates schedules to characterize the Market. This becomes the basis for customer segmentation to determine the number of eligible customers in each market segment for potential DR program participation. The DR study combined like customer segments in Washington and Idaho because Avista utilities operates across both states.

The study compared Avista's market segments to national DR programs to identify relevant DR programs for analysis.

Figure 6.1: Program Characterization Process



This process identified several DR program options shown in Table 6.1. The different types of DR programs include two broad classifications: Curtailable/Controllable DR and Rates programs.

Curtailable/Controllable DR programs represent firm, dispatchable, and reliable resources to meet peak-period loads. This category includes Direct Load Control (DLC), Firm Curtailment (FC), thermal and battery storage, and ancillary services. Avista added

[4] Avista added an extra five years to study a 25-year time period.

large industrial curtailment and standby generation; these programs were not part of the AEG study.

Rates options offer non-firm load reductions that might not be available when needed, but rather create a reliable pattern of potential load reduction. Pricing options include time-of-use, variable peak, and real time pricing. Each option requires a new rate tariff.

Table 6.1: Demand Response Program Options by Market Segment

DR Program		Participating Market Segment				Season Impacted	
Program Type	Program Option	Res.	Sm. Com.	Large. Com./ Ind.	Extra Large Com./ Ind.	Winter	Summer
Curtailable/ Controllable DR	DLC Central AC	X	X				X
	DLC Smart Thermostat – Cooling	X	X				X
	DLC Smart Thermostat – Heating	X	X			X	
	DLC Water Heating	X	X			X	X
	DLC Vehicle Charging	X				X	X
	DLC Smart Appliances	X	X			X	X
	Third Party Contracts		X	X	X	X	X
	Thermal Energy Storage		X	X	X		X
	Battery Energy Storage	X	X	X	X	X	X
	Behavioral	X				X	X
	Ancillary Services	X	X	X	X	X	X
	Large Industrial Curtailment				X	X	X
	Standby Generation			X	X	X	X
Rates	Time-of-Use Opt-in	X	X	X	X	X	X
	Time-of-Use Opt-out	X	X	X	X	X	X
	Variable Peak Pricing Rates	X	X	X	X	X	X
	Real Time Pricing			X	X	X	X

Demand Response Program Descriptions

Direct Load Control

A DLC program targeting Avista's Residential and General Service customers in Idaho and Washington would directly control electric space heating load in winter, space-cooling load in the summer, and water heating load throughout the year through a load control switch or programmable thermostat. Central electric furnaces, heat pumps, and central air-conditioners would cycle on and off during high-load events. Water heaters would completely turn off during the DR event period. Water heaters of all sizes are eligible for control. Smart appliances included in the analysis include refrigerators, clothes washers and dryers. Typically, DLC programs take five years to ramp up to maximum participation levels.

Third Party Contracts - Firm Curtailment

Customers participating in a firm curtailment program agree to reduce demand by a specific amount or to a pre-specified consumption level during the event. In return, participants receive fixed incentive payments. Customers receive payments even if they never receive a load curtailment request. The capacity payment typically varies with the firm reliability-commitment level. In addition to fixed capacity payments, participants receive compensation for reduced energy consumption. Because the program includes a contractual agreement for a specific level of load reduction, enrolled loads have the potential to replace a firm generation resource. Penalties are a possible component of a firm curtailment program.

Customers with operational flexibility are attractive candidates for firm curtailment programs. Examples of customer segments with high participation possibilities include large retail establishments, grocery chains, large offices, refrigerated warehouses, water- and wastewater-treatment plants, and industries with process storage (e.g. pulp and paper, cement manufacturing). Customers with operations requiring continuous processes, or with relatively inflexible obligations, such as schools and hospitals, generally are not good candidates.

In most cases, third parties administer firm curtailment programs and are responsible for all aspects of program implementation, including program marketing and outreach, customer recruitment, technology installation, and incentive payments. Avista could contract with a third party to deliver a fixed amount of capacity reduction over a certain specified timeframe. The contracted capacity reduction and the actual energy reduction during DR events is the basis of payment to the third party.

Thermal Energy Storage

Thermal energy storage technologies draw electricity during low demand periods and store it as heat with a thermal storage medium, such as bricks, water, or ice sealed inside the unit. A variable speed fan can automatically circulate heat or cool throughout a room using the stored energy (heat or ice) rather than having to draw energy from the grid during peak times.

Battery Energy Storage
Battery energy storage technologies draw electricity during low demand periods and store it for use during peak times. This study assumes energy is stored using electrochemical processes.

Behavioral
This program is a voluntary reduction in response to digital behavioral messaging. These programs typically occur in conjunction with Energy Efficiency behavior report programs.

Ancillary Services
For DR providing ancillary (spinning, non-spinning, regulation) and load following services, loads need to respond within a very short notification period, typically less than 10 minutes. These "Fast DR" programs providing load following services are relevant in the context of integrating intermittent renewable resources such a solar and wind. A subset of participants from other DR programs such as DLC and firm curtailment customers could supply these services if called upon.

Time of Use Rates (Opt-In or Opt-Out)
A Time of Use (TOU) rate is a time-varying rate. Relative to a revenue-equivalent flat rate, the rate during on-peak hours is higher, while the rate during off-peak hours is lower. This provides customers with an incentive to shift consumption out of the higher-price on-peak hours to the lower cost off-peak hours. TOU is not a demand-response option, per se, but rather a permanent load shifting opportunity. Large price differentials are generally more effective than smaller differentials.

The DR study considered two types of TOU pricing options. With an opt-in rate, participants voluntarily enroll in the rate. An opt-out rate places all customers on the time-varying rate, but they may opt-out and select another rate.

Variable Peak Pricing
Similar to TOU pricing, variable peak pricing changes prices daily to reflect system conditions and costs. Under a variable peak pricing program, on-peak prices for each weekday are made available the previous day. Variable peak pricing bills customers for their actual consumption during the billing cycle at these prices. Over time, establishment of event-trigger criteria enables customers to anticipate events based on hot weather or other factors. System contingencies and emergencies are good candidates for variable peak pricing.

Real-Time Pricing
Under real-time pricing, electricity rates vary by the hour, according to wholesale electricity market. Real-time pricing incentivizes customers to move a portion of their usage away from peak times to take advantage of lower electricity prices. The analysis removed residential, small, and medium businesses because typically only large and extra-large customers participate in these types of programs according to AEGs findings. Studies show dynamic pricing programs, such as critical peak pricing, vary according to whether customers have enabling technology to automate their response. For large and extra-large general service customers, the enabling technology is

automated demand response implemented through energy management and control systems.

Large Industrial Curtailment

The IRP includes a 25 MW large industrial curtailment program to take advantage of potential programs with one of Avista larger industrial customers. Program sizes are likely to be around 25 MW, but there is potential for up to 50 MW depending on the customers' ability to be flexible. The concept of this program is to develop parameters for customer curtailment and compensate customers a fixed amount or an amount per curtailment.

Standby Generation

This program uses customer generators for a limited number of hours for peak requirements, operating reserves, and potentially for voltage support on certain distribution feeders.

Demand Response Program Participation

The steady-state participation assumptions rely on an extensive database of existing program information and insights from market research results, and represent "best-practices" estimates for participation in these programs. The industry commonly follows this approach for arriving at achievable potential estimates. However, practical implementation experience suggests that uncertainties in factors such as market conditions, regulatory climate, and economic environment are likely to influence customer participation in DR programs.

Once initiated, DR options require a time-period to ramp up and reach a steady state because customers need time for education, outreach, and recruitment; in addition to the physical implementation and installation of any hardware, software, telemetry, or other equipment. DR programs require careful consideration of the customer engagement aspects of these options. DR programs included in the study have ramp rates generally in a three-year to five-year timeframe to reach their steady state.

Demand Response Program Hierarchy

Independent assessments of DR programs considered each program as a standalone offering. As such, this approach does not account for participation overlaps among DR options targeted at the same customer segment and therefore savings and cost results for individual DR programs are not additive. The standalone analysis results help provide a comparative assessment of individual DR programs and costs and are useful for selection of DR programs in a program portfolio.

If Avista offers more than one program, then the potential for double counting exists. To address this possibility, a participation hierarchy defined the order in which customers take the programs for an integrated approach. The study computed savings and costs under this scenario.

Standalone DR programs are in the results section because of their use in modeling. For detailed results using the integrated estimates, program participation rates and estimated peak reductions by program per market segment, please see Appendix A, AEG's slide deck of Avista's Demand Response Potential Assessment study.

Demand Response Program Results

Tables 6.2 through 6.5 show demand savings from individual DR programs for selected years of the analysis. These savings represent combined savings from DR options in Avista's Idaho and Washington service territories.

Key findings:

- Third-party contracts have the highest savings potential;
- Opt-out TOU and variable peak pricing options have the second highest savings potential; and
- DLC for residential customers provides the third highest savings potential.

Table 6.2: Demand Response Achievable Potential (MW) – Winter DLC

Sector	Option	2021	2022	2030	2040
Residential	DLC Central AC	-	-	-	-
	DLC Water Heating	1.4	4.3	15.6	17.5
	DLC Smart Appliances	0.3	0.8	2.8	3.1
	DLC Smart Thermostats - Cooling	-	-	-	-
	DLC Smart Thermostats - Heating	1.3	3.9	14.5	16.8
	DLC Electric Vehicle Charging	0.0	0.0	0.6	1.1
C&I	DLC Central AC	-	-	-	-
	DLC Water Heating	0.1	0.4	1.6	1.7
	DLC Smart Appliances	0.0	0.1	0.3	0.4
	DLC Smart Thermostats - Cooling	-	-	-	-
	DLC Smart Thermostats - Heating	0.2	0.7	2.7	3.0
	Third Party Contracts	3.4	9.5	23.0	23.2
	Large Industrial Curtailment	25.0	25.0	25.0	25.0
	Standby Generation	5.0	10.0	31.5	36.9
Total		**36.7**	**54.7**	**117.6**	**128.7**

Table 6.3: Demand Response Achievable Potential (MW) – Summer DLC

Sector	Option	2021	2022	2030	2040
Residential	DLC Central AC	0.5	1.4	5.4	6.2
	DLC Water Heating	1.4	4.3	15.6	17.5
	DLC Smart Appliances	0.3	0.8	2.8	3.1
	DLC Smart Thermostats - Cooling	0.5	1.4	5.4	6.2
	DLC Smart Thermostats - Heating	-	-	-	-
	DLC Electric Vehicle Charging	0.0	0.0	0.6	1.1
C&I	DLC Central AC	0.1	0.4	1.5	1.8
	DLC Water Heating	0.1	0.4	1.6	1.7
	DLC Smart Appliances	0.0	0.1	0.3	0.4
	DLC Smart Thermostats - Cooling	0.1	0.4	1.5	1.8
	DLC Smart Thermostats - Heating	-	-	-	-
	Third Party Contracts	3.0	8.5	20.7	20.9
	Large Industrial Curtailment	25.0	25.0	25.0	25.0
	Standby Generation	5.0	10.0	31.5	36.9
Total		**36.0**	**52.7**	**111.9**	**122.6**

Table 6.4: Winter Demand Response Achievable Potential (MW)

Sector	Option	2021	2022	2030	2040
Residential	Time-of-Use Opt-in	0.6	1.9	6.5	6.9
	Time-of-Use Opt-out	28.3	24.3	22.1	23.5
	Variable Peak Pricing Rates	2.1	6.2	21.8	23.1
	Ancillary Services	0.0	0.0	0.1	0.2
	Battery Energy Storage	0.1	0.2	2.4	4.4
	Behavioral	0.8	1.7	3.5	3.7
C&I	Time-of-Use Opt-in	0.1	0.4	1.7	1.7
	Time-of-Use Opt-out	8.2	9.3	9.4	9.4
	Variable Peak Pricing Rates	0.3	1.5	6.2	6.4
	Real Time Pricing	0.1	0.3	1.1	1.1
	Ancillary Services	2.2	2.2	2.2	2.3
	Thermal Energy Storage	-	-	-	-
	Battery Energy Storage	0.0	0.0	0.4	0.8
Total		**42.8**	**48.0**	**77.4**	**83.5**

Table 6.5: Summer Demand Response Achievable Potential (MW)

Sector	Option	2021	2022	2030	2040
Residential	Time-of-Use Opt-in	0.6	1.8	6.4	6.8
	Time-of-Use Opt-out	27.7	23.8	21.7	23.0
	Variable Peak Pricing Rates	2.0	6.1	21.3	22.6
	Ancillary Services	0.0	0.0	0.1	0.2
	Battery Energy Storage	0.1	0.2	2.4	4.4
	Behavioral	0.8	1.6	3.4	3.6
C&I	Time-of-Use Opt-in	0.1	0.4	1.5	1.5
	Time-of-Use Opt-out	7.2	8.3	8.4	8.4
	Variable Peak Pricing Rates	0.3	1.3	5.6	5.7
	Real Time Pricing	0.1	0.3	1.0	1.0
	Ancillary Services	1.9	2.0	2.0	2.1
	Thermal Energy Storage	0.0	0.2	0.8	0.8
	Battery Energy Storage	0.0	0.0	0.4	0.8
Total		**40.8**	**46.0**	**75.0**	**80.9**

Demand Response Peak Credit

For reliability planning, Avista translates the peak savings identified by AEG into a peak credit, meaning the percentage of the capacity it contributes to meeting Avista reliability criteria in peak load periods. This process is an Effective Load Carrying Capability (ELCC) analysis. Refer to Chapter 9 for a more in-depth discussion of Avista's ELCC methods. A DR program's assigned peak credit will differ depending on its duration. Programs interrupting loads for longer periods will receive larger peak credits, but the peak credit depends on whether or not there is a "snap back" effect. Loads without a snap back effect shed load permanently, but loads exhibiting the snap back effect are higher later due to the reduction from the DR program. Avista only had adequate time to conduct generic DR programs assuming up to eight hours of load reduction. Our results were, resulting a 60 percent peak credit for an 8-hour DR load reduction. Avista concludes this is a result of limited energy reduction when Avista needs of for winter energy in addition to winter peak reductions.

Demand Response Program Cost Estimates

The study includes cost estimates to achieve the savings results for both individual DR programs considered on a standalone basis and on an integrated basis. This takes into consideration any customer participation overlap that may occur if Avista implements multiple programs simultaneously. The study modeled standalone costs to be consistent with the savings modeling methodology. The key findings are pricing options have the lowest cost and DLC of heating loads with smart thermostats have the second lowest cost.

Table 6.6: 2021 Levelized Costs by DR Program (Standalone)

2021 Levelized Cost	$/kW-yr Winter	$/kW-yr Summer
Ancillary Services	$120	$133
Battery Energy Storage	$445	$445
Behavioral	$147	$150
DLC Central AC	$0	$144
DLC Electric Vehicle Charging	$769	$769
DLC Smart Appliances	$298	$298
DLC Smart Thermostats - Cooling	$0	$152
DLC Smart Thermostats - Heating	$54	$0
DLC Water Heating	$233	$233
Large Industrial Curtailment[5]	n/a	n/a
Standby Generation	$99.6	$99.6
Real Time Pricing	$124	$139
Thermal Energy Storage	$0	$730
Third Party Contracts	$90	$100
Time-of-Use Opt-in	$53	$55
Time-of-Use Opt-out	$69	$72
Variable Peak Pricing Rates	$24	$25

Washington State House Bill 1444 Appliance Standards

The newly enacted legislation from Washington State House Bill 1444 (HB 1444) includes new design requirements for tanked style water heaters be manufactured with a CTA-2045 communication port that enables demand response. The Washington State Department of Commerce is currently in the rulemaking process to support HB 1444.

Using a recent study published November 9, 2018 by the Bonneville Power Administration (BPA), AEG analyzed costs and impacts for a CTA-2045 water heater DR program. Impacts from the BPA study suggest a lower impact for CTA-2045 water heaters than traditional water heater demand response programs included in the Seventh Power Plan. Even with increased participation the CTA-2045 water heaters

[5] Avista is not including pricing for this program, as its economics is dependent on the negotiated price between the customer and Avista.

would allow, it is not enough difference to overcome the reductions in impacts. As a result, the CTA-2045 water heater DR program was not included in Avista's current IRP modeling. Avista will revisit this DR program with guidance from the Department of Commerce's final rulemaking in Washington State.

7. Long-Term Position

This chapter describes the analytical framework used to develop Avista's net resource position. It describes reserve margins held to meet peak loads, risk-planning metrics used to meet hydroelectric variability, and plans to meet renewable goals set by Washington's Energy Independence Act (EIA) and the Clean Energy Transformation Act (CETA).

Avista has unique attributes affecting its ability to meet peak load requirements. It connects to several neighboring utility systems, but is only 5 percent of the total regional load. Annual peaks can occur either in the winter or in the summer; but Avista is winter peaking on a planning basis due to periods of extreme cold weather conditions. The winter peak generally occurs in December or January, but may also happen in November or February. As described in Chapter 4 – Existing Supply Resources, Avista's resource mix contains roughly equal amounts of hydroelectric and thermal generation. Hydroelectric resources meet most of Avista's flexibility requirements for load and intermittent generation, though thermal generation is playing a larger role as load growth and intermittent generation increase flexibility demands.

Section Highlights

- Avista's first long-term capacity deficit net of energy efficiency is in 2026; the first energy deficit is also in 2026.
- By 2021, clean resource generation equals 78 percent of retail sales.
- Avista exceeds renewable energy targets for Washington's Energy Independence Act throughout this IRP.
- The regional resource adequacy situation is at risk due to planned coal plant retirements and load growth without the addition of new resources.

Reserve Margins

Planning reserves accommodate situations when load exceeds and/or resource output falls below expectations due to adverse weather, forced outages, poor water conditions, or other unplanned events. Reserve margins, on average, increase customer rates when compared to resource portfolios without reserves because of the cost of carrying rarely used generating capacity. Reserve resources have the physical capability to generate electricity, but most have high operating costs that limit their normal dispatch and revenue.

There is no industry standard reserve margin level as it is difficult to enforce standardization across systems with varying resource mixes, system sizes, and transmission interconnections. NERC defines reserve margins as 15 percent for predominately-thermal systems and 10 percent for predominately-hydroelectric systems[1], but does not provide an estimate for energy limited system as such with Avista and the northwest due to hydro.

[1] http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

Avista and the region's hydroelectric system is energy constrained, so the 10 or 15 percent metrics from NERC do not adequately define our planning margin. Beyond planning margins, as defined by NERC, a utility must maintain operating reserves to cover forced outages on the system. Avista includes operating reserves in addition to a planning margin. Per Western Electric Coordinating Council (WECC) requirements, Avista must maintain 3 percent of control area load and 3 percent of on-line control area generation plus Frequency Response Requirement (FRR) of 24 megawatts. Avista must also maintain reserves to meet load following and regulation requirements of within-hour load and generation variability, this amount equals 16 MW at the peak hour.

Avista's planning margin in the 2017 IRP was 14 percent in the winter and 7 percent in the summer totaling a 22.6 percent planning margin (with reserves). This was a result of a study of Avista resources and loads using 1,000 simulations varying weather for loads and thermal generation capability, forced outage rates on generation, water conditions for hydro plants, and wind generation. The requirement of the study was to quantify by percentage the amount of additional generation above expected load to serve all load in 95 percent of the simulations, resulting in a 5 percent loss of load probability or less.

2020 IRP Resource Adequacy Assessment

Early in the IRP process, Avista identified the same 14 percent planning margin requirement would be necessary for meeting future load in its second Technical Advisory Committee (TAC) meeting as in prior IRPs. This study assumes 250 MW is available from the wholesale market,[2] and Avista would need to add 240 MW of CTs (assumes two units). This analysis also assumes Colstrip Units 3 and 4 would be available to serve loads.

With the passage of CETA, a new resource adequacy assessment was completed with Avista's Reliability Assessment model (ARAM) for 2030. This assessment included the following updated assumptions: the removal of Colstrip Units 3 and 4, an updated load forecast, and adjustments to resource maintenance schedules during the winter. This study and the prior studies are in Table 7.1 with monthly and annual LOLP results from the ARAM. The new study is resource adequate in a post CETA planning environment (achieve the 5 percent LOLP) with 350 MW of capacity consisting of three new CTs. The 350 MW equates to a planning margin of 16 percent compared to 14 percent for the winter peak in the last IRP for the year 2030. Avista did not study other years for resource adequacy because of time and resource constraints.

As will be discussed in Chapter 11, a higher planning margin of 18 percent was ultimately required to achieve the 5 percent LOLP of the resources selected in the PRS. Ultimately, a combination of storage and intermittent resources requires higher planning margins than historical portfolios with constant fuel supplies. In the end, the planning margin target

[2] The 250 MW of market availability was initially determined in the 2013 IRP. This study addresses the tradeoff of market exposure versus higher planning margins. In the end, this is a tradeoff between higher rates and higher reliability risk due to market reliance. Avista settled on 240 MW originally for market reliance as it was an acceptable level of risk as compared to added capacity cost.

is rather a simplified measure of resource need; the quantity of resources needed to achieve 5 percent LOLP determines the actual need.

Table 7.1: 2020 Reliability Study Results

Month	Pre-CETA No Additions w/ Colstrip	Post-CETA No Additions w/o Colstrip	Post-CETA 350 MW CTs
Jan	12.3%	24.3%	1.5%
Feb	7.0%	13.8%	1.1%
Mar	0.7%	1.5%	0.1%
Apr	0.0%	0.0%	0.0%
May	0.0%	0.0%	0.0%
Jun	0.0%	0.0%	0.0%
Jul	1.0%	9.3%	0.2%
Aug	2.2%	12.4%	0.2%
Sep	0.1%	0.5%	0.0%
Oct	0.1%	0.3%	0.0%
Nov	1.8%	3.8%	0.1%
Dec	9.3%	17.2%	2.4%
Annual	27.9%	54.3%	5.2%

Balancing Loads and Resources

The single-hour future load and resource projection is a simple method to identify any shortages. It highlights the potential of not serving loads in hours when the hydroelectric system (or future storage system) does not have enough energy available to operate at peak levels. In past IRPs, Avista used a three-day sustained peak analysis to illustrate this concern. This method looked at the ability to serve 18 hours of peak loads over a three-day period. While this method provides a good overview of the real problem of serving peak loads, the single hour was typically the larger shortfall. Avista addresses these requirements moving to the LOLP method for reliability planning but ultimately using the single and sustained peak analysis as supplementary insight. Figure 7.1 illustrates the winter balance of loads and resources for the peak hour. The first significant winter capacity deficit occurs in January 2026 when Avista assumes Colstrip exits the portfolio for IRP purposes. In October 2026, the deficit will increase when the Lancaster PPA expires.

Avista plans to meet summer peak load with a smaller planning margin than in the winter. Summer months include operating reserve and regulation obligations in addition to a 7 percent planning margin (see Figure 7.2). Market purchases in the deep regional market should satisfy any weather-induced load variation or generation forced outage that otherwise would be included in the planning margin as is the case in the higher winter planning margin. The reliability analysis in Table 7.1 shows winter as the primary deficit period as resource additions to serve winter peaks meet smaller summer deficits as well.

Figure 7.1: Winter One-Hour Capacity Load and Resources

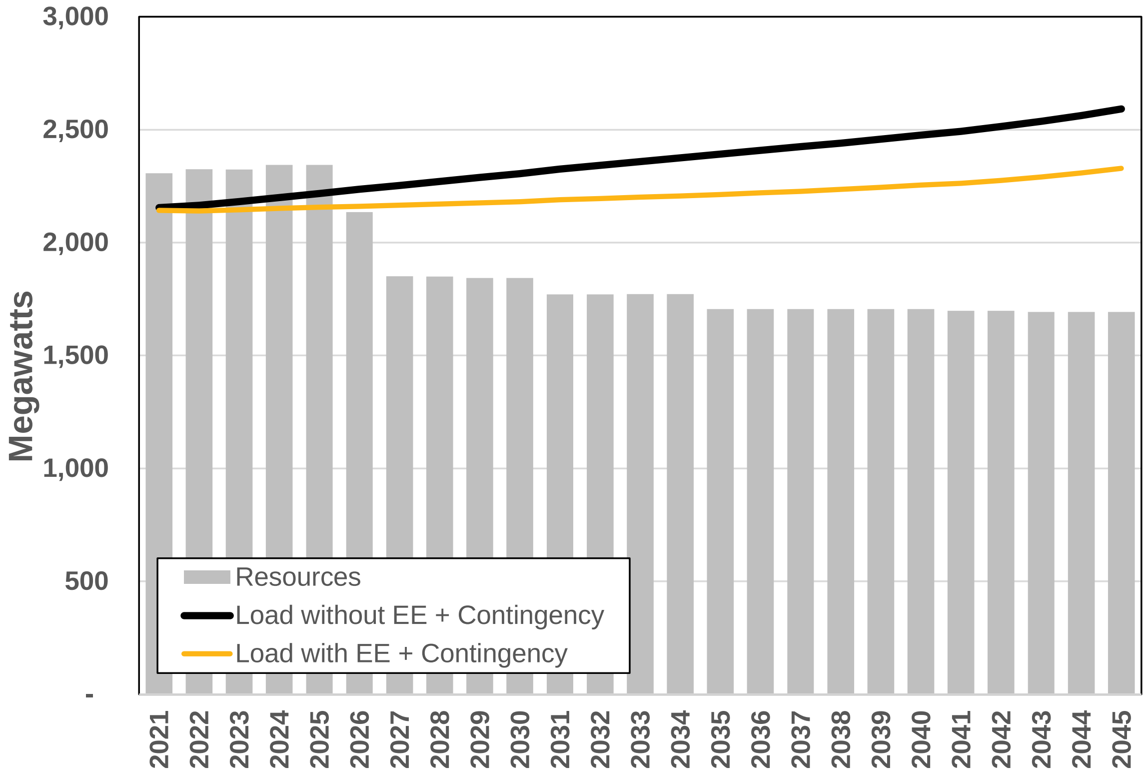
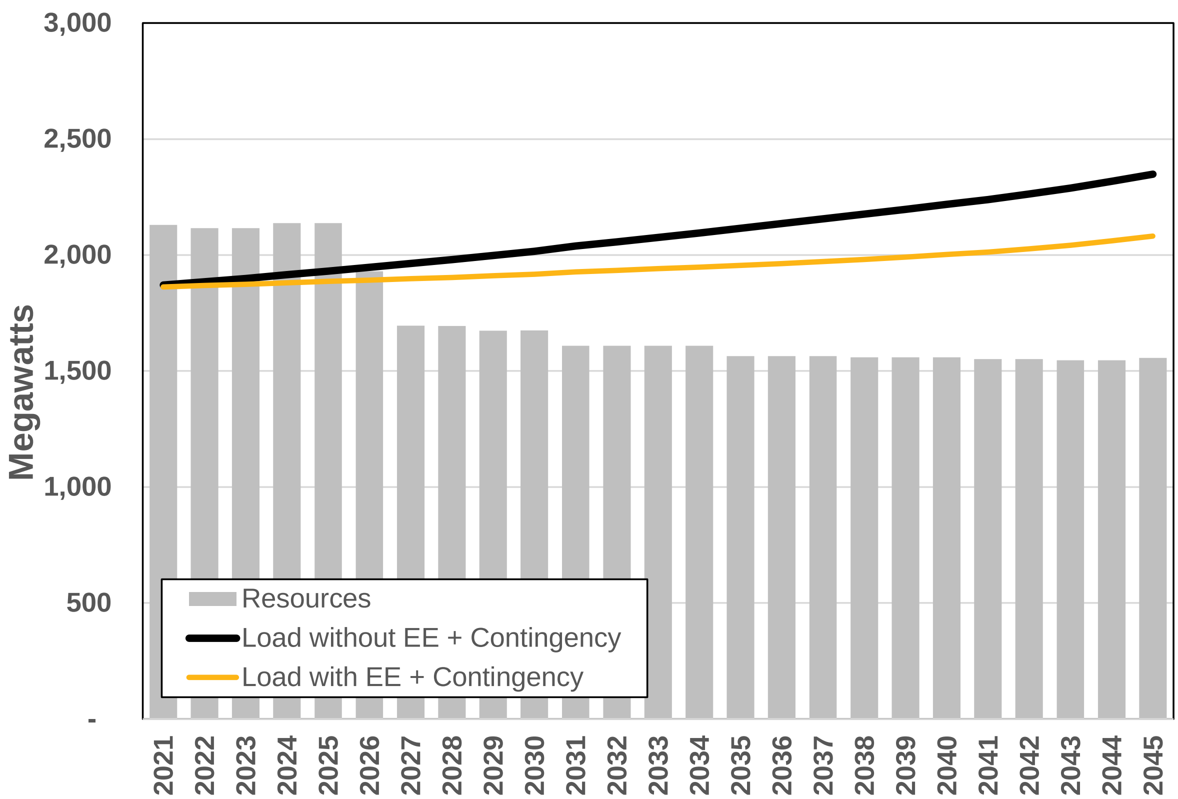


Figure 7.2: Summer One-Hour Capacity Load and Resources

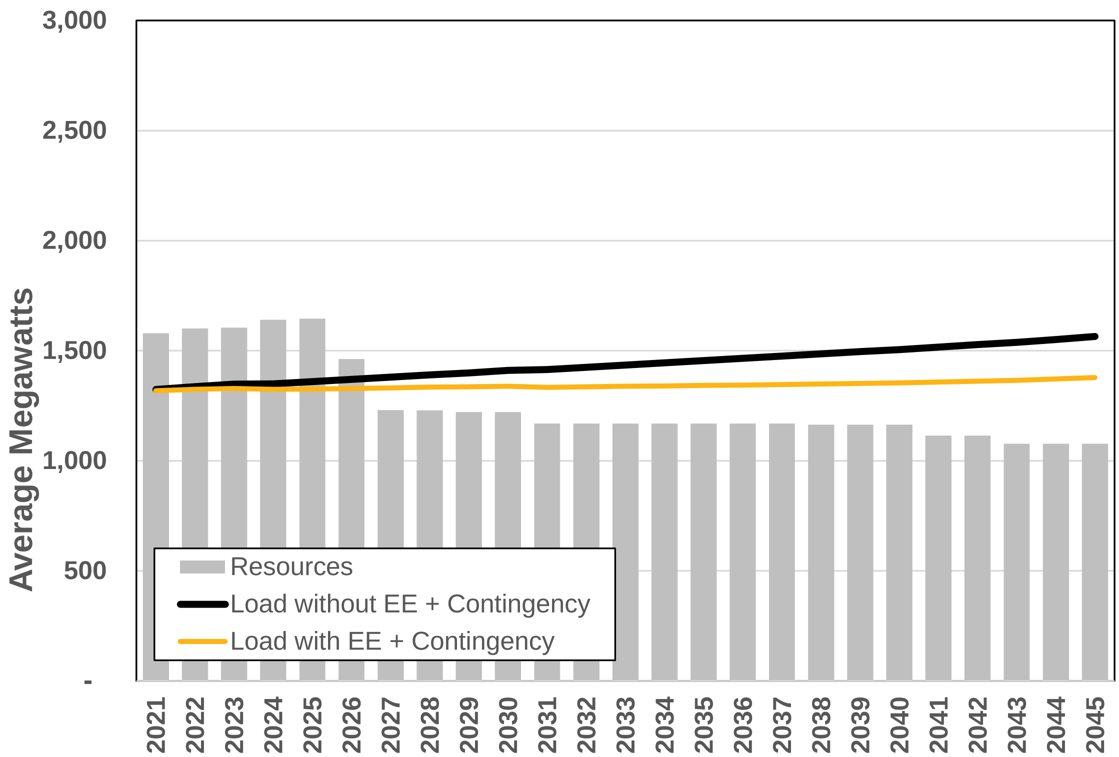


Energy Planning

For energy planning, resources must be adequate to meet customer requirements even when loads are high for extended periods, or a sustained outage limits the contribution of a resource. Where generation capability is inadequate to meet these variations, customers and the utility must rely on the short-term electricity market. In addition to load variability, Avista holds energy-planning margins for variations in month-to-month hydroelectric generation.

As with capacity planning, there are differences in regional opinions on the proper method for establishing energy-planning margins. Many utilities in the Northwest base their energy planning margins on the amount of energy available during the "critical water" period of 1936/37.[3] The critical water year of 1936/37 is low on an annual basis, but it does not represent a low water condition in every month. The IRP could target resource development to reach a 99 percent confidence level to deliver energy to its customers, and it would significantly decrease the frequency of its market purchases. However, this strategy requires investments in approximately 200 MW of generation in addition to the capacity planning margins included in the Expected Case of the 2017 IRP to cover a one-in-one-hundred year event. Investments to support this high level of reliability would increase pressure on retail rates for a modest benefit. Avista plans to the 90th percentile for hydroelectric generation. Using this metric, there is a one-in-ten-year chance of needing to purchase energy from the market in any given month over the IRP timeframe.

Figure 7.3: Annual Average Energy Load and Resources



[3] The critical water year represents the lowest historical generation level in the streamflow record.

Washington State Renewable Portfolio Standard

Washington's Energy Independence Act (EIA) requires utilities with more than 25,000 customers to source 9 percent of their energy from qualified renewables through 2019 and 15 percent by 2020. Utilities also must acquire all cost effective conservation as explained in Chapter 5 – Energy Efficiency. In 2011, Avista signed a 30-year PPA with Palouse Wind to help meet the EIA goal. In 2012, an amendment to the EIA allowed Avista's Kettle Falls project to qualify for the EIA goals beginning in 2016. Since the last IRP, Avista acquired Rattlesnake Flats wind and Adam-Nielson Solar[4] both qualify for EIA compliance.

Table 7.2 shows the forecast for RECs[5] Avista needs to meet the EIA renewable requirement and the amount of qualifying resources already in Avista's generation portfolio. Any utility in compliance with CETA is also compliant with the EIA. This table does not include the right to roll credits forward or backward by one year. Avista uses this banking flexibility to manage variation in production.

Table 7.2: Washington State EIA Compliance Position Prior to REC Banking (aMW)

	2018	2020	2025	2030	2035
Two-Year Rolling Average Washington Retail Sales Estimate	649.6	660.1	669.2	680.8	689.2
Renewable Goal	97.4	99.0	100.4	102.1	103.4
Incremental Hydroelectric	18.8	18.8	18.8	18.8	18.8
Net Renewable Goal	78.6	80.2	81.5	83.3	84.5
Other Available REC's	127.9	127.9	133.5	133.5	34.8
Palouse Wind with Apprentice Credits	43.4	43.4	43.4	43.4	0.0
Kettle Falls	34.8	34.8	34.8	34.8	34.8
Rattlesnake Flats[6]	49.6	49.6	49.6	49.6	0.0
Adams Nielson Solar	0.0	0.0	5.6	5.6	0.0
Net Renewable Position (before rollover RECs)	**49.3**	**47.7**	**51.9**	**50.2**	**-49.7**

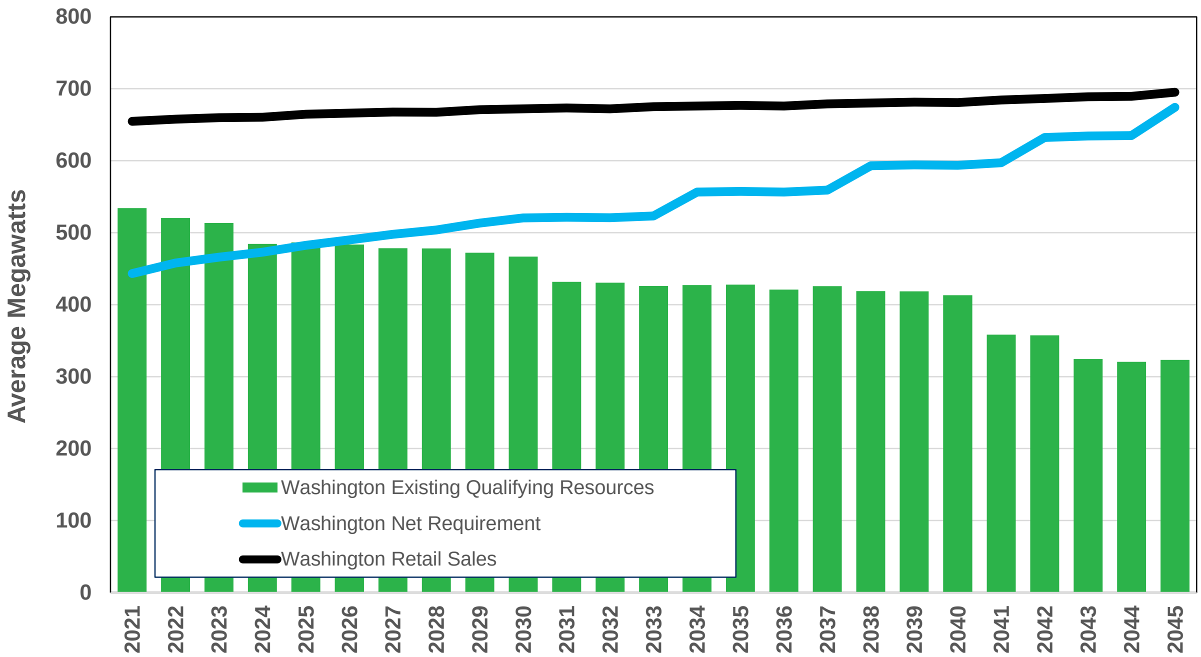
[4] Adam-Neilson will qualify after the Solar Select program ends.
[5] These RECs are qualifying RECs within Avista system. For state compliance purposes the Company my transfer RECs between state's allocation shares at market prices. Further, Avista may sell excess RECs to lower customer rates.
[6] Rattlesnake Flat may also qualify for the apprentice credits, creating a 20 percent adder to the REC amount for compliance.

Washington State Clean Energy Transformation Act (CETA)

Washington State's CETA requires serving 100 percent of state retail sales with clean energy by 2045. In 2030, up to 20 percent of this clean energy may use an alternative compliance mechanism to satisfy the requirement. Avista did not model all alternative compliance options for this plan due to the fact rules are not yet in place to define all potential programs qualifying for this designation with the exception of unbundled RECs. For this IRP, Avista assumes REC's from Idaho's share of the hydroelectric system is limited to the 20 percent portion of its compliance, and its contribution declines each year through 2045. Although, Idaho's hydro share may qualify for meeting all targets in Washington subject to rulemaking and Idaho's interest in selling the renewable attributes associated with the generation. Between now and 2030, Avista is expected to ramp into the 80 percent goal, although the rate of the ramp is to be proposed by the utility. Avista set the target of 75 percent clean by 2025 and 80 percent by 2030. Figure 7.4 shows this target as the blue line. After 2030, the blue line increases every four years until it is close to meeting 100 percent of retail sales.

The target never reaches the retail sales (black line) due to a provision in CETA subtracting PURPA purchases from retail sales. The figure shows Avista's current qualifying resources in green. These include Washington's entire allocated share of the hydroelectric system (both owned and PPAs) and the renewable resources shown in Table 7.2. Idaho customers also have a claim to their share of renewable attributes, but Avista assumes like in the EIA the reassigning of these attributes to Washington customers with compensation to Idaho customers for the transfer. Given these estimates, Avista needs to acquire additional renewable resources for CETA beginning in 2026 for Washington customers as the shortfall reaches nearly seven average megawatts. The Company will be short of the 80 percent non-emitting requirement by 54 aMW in 2030 and 350 aMW short of the 100 percent 2045 goal. Avista plans to comply with the 20 percent component of the law by transferring RECs from Idaho to Washington in a similar manner as the EIA compliance. Avista acknowledges final rule making regarding complying with the CETA law may alter Avista needed either higher or lower than set in this plan. Avista will continue to work with the 2020 WUTC and other partings in the rulemaking process to finalize the rules for preparation of the 2021 IRP.

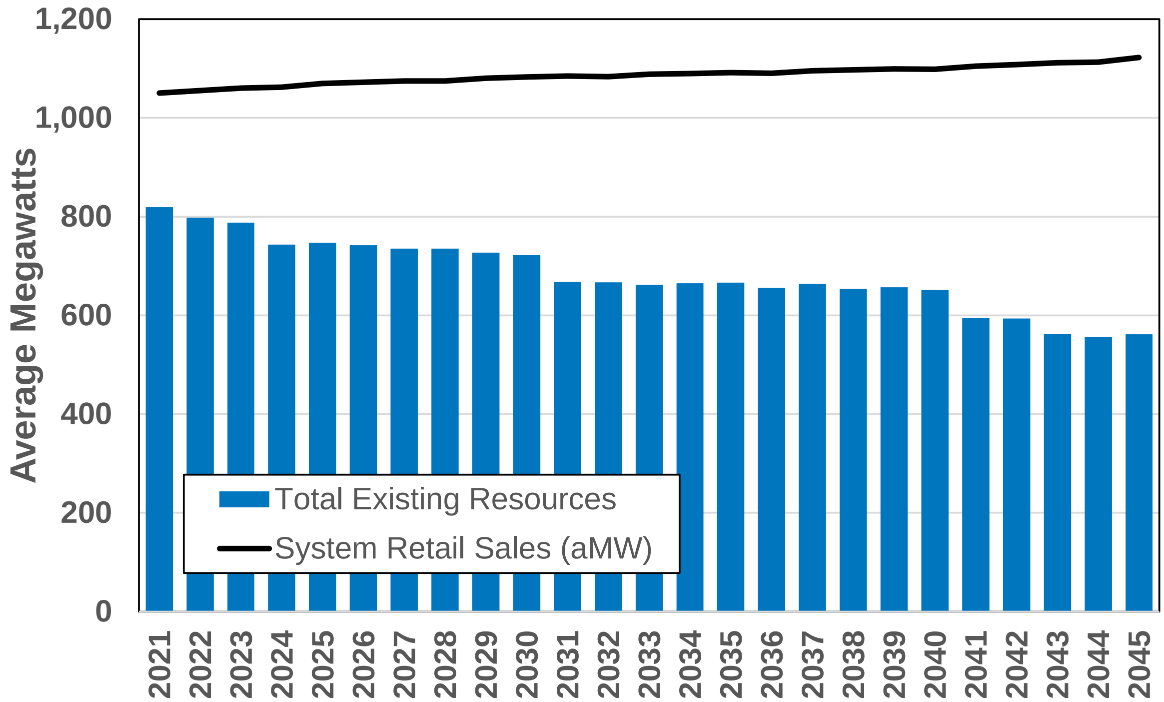
Figure 7.4: Washington State CETA Compliance



Avista's Clean Energy Goal

Avista set a corporate goal to serve all retail customers with 100 percent carbon neutral energy by 2027 and deliver 100 percent clean energy by 2045 for the entire system. From a resource planning perspective, the 2027 goal entails ownership or control of renewable resources or RECs equal to retail sales by 2027 and phase out all carbon producing generation by 2045. Each of these goals must consider cost implications in relation to the technical feasibility. This section discusses the amount of energy needed to meet the corporate goals. By 2021, Avista will have clean generation over the course of a year to meet 78 percent of retail sales. By 2030, Avista would need to acquire an additional 340 aMW of clean energy or RECs to achieve its 2027 goal; by 2045, the deficit grows to nearly 560 aMW. In addition to the energy need in 2045, the Company will need to add 636 MW to meet the current resource gap and also replace the 590 MW the existing thermal resources provide on a winter peak day for 1,226 MW total. This potential new capacity will need to be able to operate in cold winters and meet Avista's five percent LOLP reliability threshold.

Figure 7.5: Avista Clean Energy Goal



Regional Resource Adequacy

Avista relies on 250 MW of market power in the reliability study. If Avista chose not to rely on market power, its planning margins would be over 30 percent. Avista is not an electrical island, and other entities should be able to assist Avista when load peaks. Collectively, utilities should plan as a system and optimize resources to meet the region's needs. This may be an optimistic goal, as some utilities do not always make their excess capacity available. To gain a better understanding of the market and the region's ability to provide adequate power, Avista participates in the Northwest Power and Conservation Council's (NPCC) resource adequacy forum. In addition to this process, Avista contributed funding for a resource adequacy study by the firm E3. This study provided regional resource builds and costs for future clean energy scenarios. The last method Avista uses to review regional resource adequacy is part of its market price forecast.

Northwest Power and Conservation Council

The NPCC released its Pacific Northwest Power Supply Adequacy Assessment for 2024[7] on October 31, 2019 highlighting potential resource adequacy risks to the system. The NPCC estimates the regional 2021 LOLP to be 7.5 percent exceeding the region's threshold for resource adequacy due to announced coal plant retirements. The likelihood of lost load increases to 8.2 percent by 2024 with a regional 800 MW capacity shortage. When additional resources retire in 2026, the LOLP increases to 17 percent. Using the results from this study equates to a regional planning margin of 13.4 percent[8].

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[7] https://www.nwcouncil.org/sites/default/files/2024%20RA%20Assessment%20Final-2019-10-31.pdf.
[8] This assumes the BPA's White Book's average peak capacity for regional hydro generation and 2,500 MW of imports.

The regional analysis also conducts sensitivities regarding the level of load from economic growth and level of imports from other regions. Table 7.3 shows the range in analysis provided by the NPCC for the LOLP in the first three rows and the megawatts required of needed generation (or load reduction) in the bottom three rows. This analysis shows the region is at risk without new resources unless loads fall or the region is able to acquire winter capacity from other regions.

Table 7.3: NPCC 2024 Resource Adequacy Analysis

	Import (MW)	1,500	2,000	2,500	3,000	3,500
LOLP %	High Load (3% higher	21.1	18.0	16.0	14.4	12.0
LOLP %	Medium Load	12.5	10.2	**8.2**	6.9	5.2
LOLP %	Low Load (3% lower)	7.0	5.2	4.0	3.1	2.0
Required MW	High Load (3% higher	2,800	2,300	1,700	1,200	800
Required MW	Medium Load	1,900	1,400	**800**	400	0
Required MW	Low Load (3% lower)	900	200	0	0	0

The greatest chance of lost load occurs in the winter months, primarily January; the study found 27 percent of events were in this month, followed by 19 percent in December. The summer had a collective LOLP of 26 percent.

Energy and Environmental Economics (E3) Study

Avista participated in a regional study to understand the resource adequacy needs with different potential clean energy legislation options. This study is included as Appendix F. The first year reviewed in the study was 2018 to test the model with the existing system. The study also reviews 2030 and 2050 under multiple resource acquisition strategies. The footprint of this study includes the four northwest states, Wyoming and Utah. This is a larger footprint then Avista's traditional energy trading partners. The 2018 study determined the region meets its 5 percent LOLP with a value of 3.7 percent; but does not have sufficient capacity to meet a goal of less than 2.4 outage hours per year (6.5 hours)[9]. E3 estimates the larger region needs an "effective" planning reserve margin of 12 percent to meet the goal of less than 2.4 outage hours per year, which would require an additional 1,200 MW of resources. By 2030, the study estimates a need for an additional 5,000 MW of capacity to maintain reliability due to resource retirements and load growth.

Avista's Market Study

Avista details its market price forecast in Chapter 10, as part of this forecast is a forecast of the needs of the region to maintain resource adequacy. This forecast estimates the generation need using an estimate of system load and resources. It does not consider individual resource needs or ability to transfer power within the region. This study shows a need for 840 MW of new natural gas-fired resource capacity to maintain resource adequacy in 2025. The region requires an additional 700 MW between 2026 and 2045. In addition to the natural gas-fired capacity, the region requires 250 MW of storage by

[9] As discussed on page 36 of Appendix F.

2025 and 2,000 MW by 2045. These additions are required along with the capacity benefits included within the wind and solar required to meet state clean energy goals.

Regional Resource Adequacy Conclusions

Avista's review of regional studies and its own study show the region is at risk for not meeting customer loads today. Avista is in a strong position in the current market shortfall by exceeding its planning margin requirements through 2025. Although after 2025, Avista and many other utilities must acquire new dependable capacity resources to ensure customers have adequate power to sustain both extended cold winter and hot summer periods.

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8. Transmission & Distribution Planning

This chapter introduces the Avista Transmission and Distribution systems and provides a brief description of how Avista studies these systems and recommends projects to keep the systems functioning reliably. Avista's Transmission System is only one part of the networked Western Interconnection, so a discussion of regulations and regional planning is also provided. This chapter includes a brief summary of planned transmission projects and generation interconnection requests currently under study and provides links to documents describing these studies in more detail. This section also describes how distribution planning is now playing a role in the IRP and the rights of Avista's merchant transmissions system.

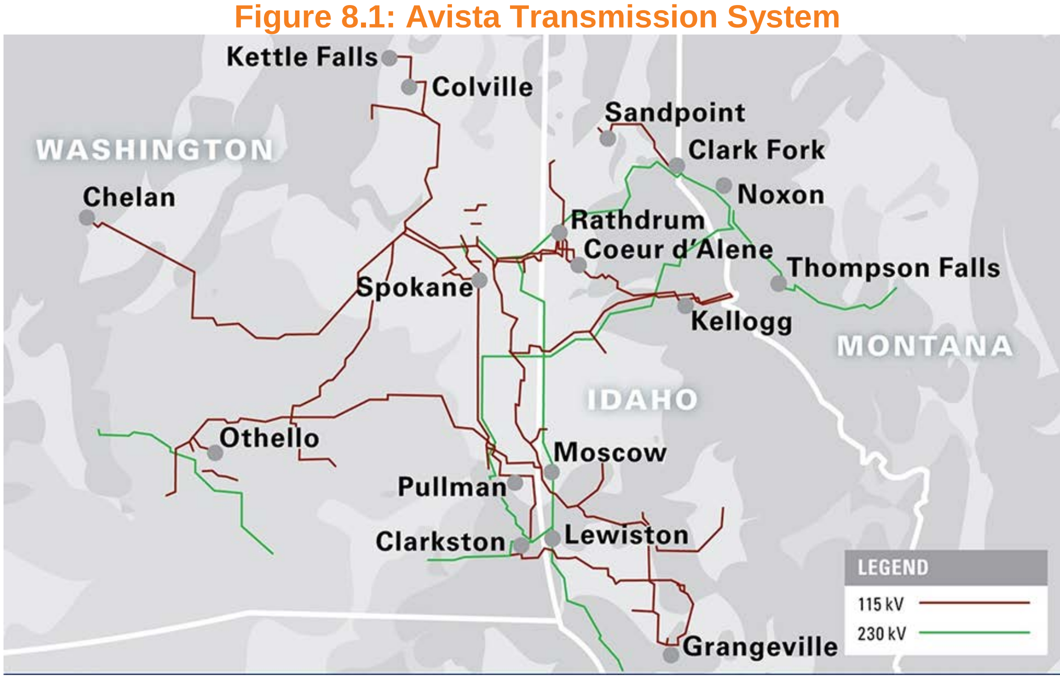
Section Highlights

- Avista actively participates in regional transmission planning forums.
- Avista develops a transmission and distribution system plan annually.
- Transmission planning estimates costs for locating new generation on the Avista system.
- Distribution planning evaluates potential storage opportunities that may allow deferment of new distribution capital as part of the IRP process.

Avista Transmission System

Avista owns and operates a system of over 2,200 miles of electric transmission facilities including approximately 700 miles of 230 kV transmission lines and 1,570 miles of 115 kV transmission lines (see Figure 8.1).

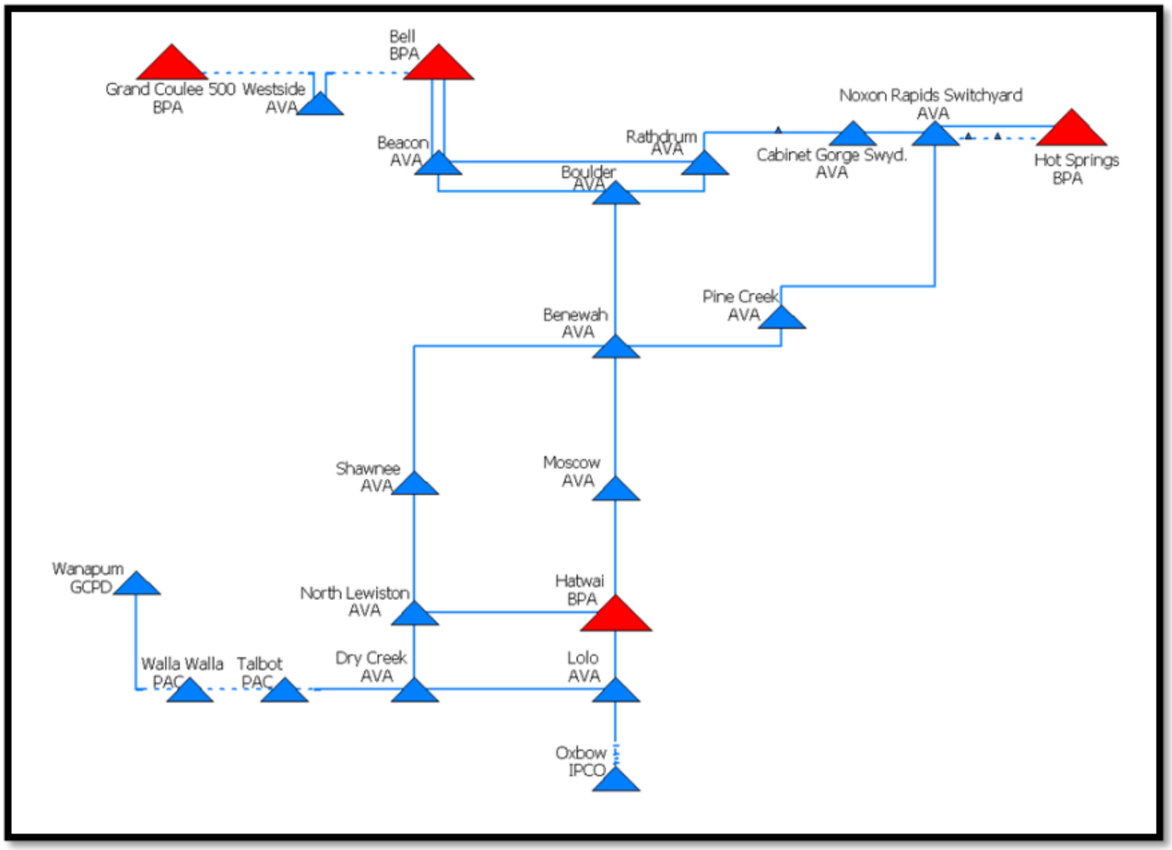
Figure 8.1: Avista Transmission System



230 kV Transmission System

The backbone of the Avista Transmission System functions at 230 kV. Figure 8.2 shows a station-level drawing of Avista's 230 kV Transmission System including interconnections to neighboring utilities. Avista's 230 kV Transmission System is interconnected to the BPA 500 kV transmission system at the Bell, Hot Springs and Hatwai Stations.

Figure 8.2: Avista 230 kV Transmission System



Transmission Planning Requirements and Processes

Avista coordinates its transmission planning activities with neighboring interconnected transmission owners. Avista complies with FERC requirements related to both regional and local area transmission planning. This section describes several of the processes and forums important to Avista transmission planning.

Western Electricity Coordinating Council

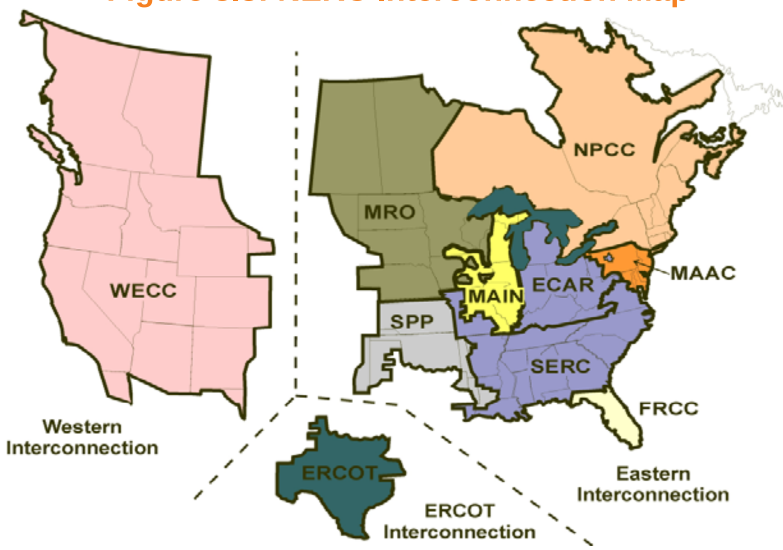
The Western Electricity Coordinating Council (WECC) is the group responsible for promoting bulk electric system reliability, compliance monitoring, and enforcement in the Western Interconnection. This group facilitates development of reliability standards and helps coordinate operating and planning among its membership. WECC is the largest geographic territory of the regional entities with delegated authority from the NERC and the FERC. It covers all or parts of 14 Western states, the provinces of Alberta and British

Columbia, and the northern section of Baja, Mexico.[1] See Figure 8.3 for the map of WECC.

RC West

RC West performs the federally mandated reliability coordinator function for a portion of the Western Interconnection. While each transmission operator within the Western Interconnection operates its respective transmission system, RC West has the authority to direct specific actions to maintain reliable operation of the overall transmission grid.

Figure 8.3: NERC Interconnection Map



Northwest Power Pool

Avista is a member of the Northwest Power Pool (NWPP), an organization formed in 1942 when the federal government directed utilities to coordinate operations in support of wartime production. The NWPP serves as a northwest electricity reliability forum, helping to coordinate present and future industry restructuring, promoting member cooperation to achieve reliable system operation, coordinating power system planning, and assisting the transmission planning process. NWPP membership is voluntary and includes the major generating utilities serving the Northwestern U.S., British Columbia and Alberta. The NWPP operates a number of committees, including its Operating Committee, the Reserve Sharing Group Committee, the Pacific Northwest Coordination Agreement (PNCA) Coordinating Group, and the Transmission Planning Committee (TPC).

ColumbiaGrid

ColumbiaGrid formed on March 31, 2006. Its membership includes Avista, BPA, Chelan County PUD, Grant County PUD, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power. ColumbiaGrid aims to enhance and improve the operational efficiency, reliability, and planned expansion of the Pacific Northwest transmission grid. Consistent with FERC requirements issued in Orders 890 and 1000, ColumbiaGrid provides an open and transparent process to develop sub-regional transmission plans, assess transmission alternatives (including non-wires alternatives),

[1] https://www.wecc.biz/Pages/About.aspx

and provides a decision-making forum and cost-allocation methodology for new transmission projects. During 2020, Avista will transition its regional transmission planning from ColumbiaGrid to the newly formed NorthernGrid. NorthernGrid is a new regional planning organization created by combining members of ColumbiaGrid and the Northern Tier Transmission Group.

Northern Tier Transmission Group

The Northern Tier Transmission Group (NTTG) formed on August 10, 2007. NTTG members include Deseret Power Electric Cooperative, Idaho Power, Northwestern Energy, PacifiCorp, Portland General Electric, and Utah Associated Municipal Power Systems. These members rely upon the NTTG committee structure to meet FERC's coordinated transmission planning requirements. Avista's transmission network has a number of strong interconnections with three of the six NTTG member systems. Due to the geographical and electrical positions of Avista's transmission network related to NTTG members, Avista participates in the NTTG planning process to foster collaborative relationships with our interconnected utilities. During 2020, Avista will transition its participation in NTTG to the newly formed NorthernGrid.

System Planning Assessment

Development of Avista's annual System Planning Assessment (Planning Assessment) encompasses the following processes:

- The Avista Local Transmission Planning Process – as provided in Attachment K, Part III of Avista's Open Access Transmission Tariff (OATT),
- The ColumbiaGrid transmission planning process (will transition to the new NorthernGrid process in 2020) – as provided in the ColumbiaGrid Planning and Expansion Functional Agreement (PEFA) and the ColumbiaGrid Order 1000 Functional Agreement,
- The requirements associated with the preparation of the annual Planning Assessment of the Avista portion of the Bulk Electric System.

The Planning Assessment, or Local Planning Report, is prepared as part of a two-year process as defined in Avista's OATT Attachment K. The Planning Assessment identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources, serve the forecasted loads of Avista's Network Customers and Native Load Customers, and meet all other Transmission Service and non-OATT transmission service requirements, including rollover rights, over a 10-year planning horizon. The Planning Assessment process is open to all interested stakeholders, including, but not limited to, Transmission Customers, Interconnection Customers, and state authorities.

Avista's OATT is located on its Open Access Same-time Information System (OASIS) at http://www.oatioasis.com/avat. Additional information regarding Avista's System Planning work is located in the Transmission Planning folder on Avista's OASIS. The Avista System

Planning Assessment is posted on OASIS. Avista's most recent transmission planning document highlights several areas for additional work including:

- **Big Bend**- Transmission system performance will significantly improve upon completion of the Benton – Othello Switching Station 115 kV Transmission Line Rebuild project. Other area improvements include the Saddle Mountain 230 kV Station project, the addition of communication aided protection schemes and other reconductor projects.

- **Coeur d'Alene**- A comprehensive long term plan is needed to mitigate both transmission and distribution capacity related performance issues in the Coeur d'Alene area. The completion of the Coeur d'Alene – Pine Creek 115 kV Transmission Line Rebuild project and Cabinet – Bronx – Sand Creek 115 kV Transmission Line Rebuild project has improved transmission system performance. The addition and expansion of distribution substations and a reinforced 115 kV transmission system are needed in the near term planning horizon.

- **Lewiston/Clarkston**- Load growth in the Lewiston/Clarkson area has contributed to heavily loaded distribution facilities. Additional performance issues have been identified related to the ability for bulk power transfer on the 230 kV transmission system. A system reinforcement project is under development.

- **Palouse**- Completion of the Moscow 230 Station rebuild project in 2014 mitigated several performance issues. The remaining issue is a potential outage of both the Moscow and Shawnee 230/115 kV transformers. An operational and strategic long term plan is under development to best address a possible double transformer outage.

- **Spokane**- Several performance issues exist with the present state of the transmission system in the Spokane area and worsen with additional load growth. The staged construction of new 230 kV facilities at the Garden Springs 230 kV and Ninth and Central 230 kV Stations to reinforce the area will be required. Dependency on Beacon Station leaves the system susceptible to performance issues for outages related to the station.

IRP Generation Interconnection Options

Table 8.1 shows the projects and cost information for each of the IRP-related studies where Avista evaluated new generation options. These studies provide a high-level view of generation interconnection costs and are similar to third-party feasibility studies performed under Avista's generator interconnection process. In the case of third-party generation interconnections, FERC policy requires a sharing of costs between the interconnecting transmission system and the interconnecting generator. Accordingly, we anticipate that all identified generation integration transmission costs will not be directly attributable to a new interconnected generator.

Large Generation Interconnection Requests

Third-party generation companies may request transmission studies to understand the cost and timelines for integrating potential new generation projects. These requests follow a strict FERC process, including three study steps to estimate the feasibility, system impact, and facility requirement costs for project integration. After this process is completed, a contract offer to integrate the project may occur and negotiations can begin to enter into a transmission agreement if necessary. Table 8.2 lists information associated with potential third party resource additions currently in Avista's interconnection queue.[2]

Table 8.1: 2020 IRP Generation Study Transmission Costs

Station	Request (MW)	POI Voltage	Cost Estimate ($ million)[3]
Kootenai County (GF)	100	230 kV	2
Kootenai County (GF)	200/300	230 kV	80-100
Rathdrum	25/50/100	115 kV	<1
Rathdrum	200	115 kV	55
Rathdrum	50/100	230 kV	<1
Rathdrum	200	230 kV	60
Benewah	100/200	230 kV	<1
Tokio	50/100	115	<1, 20
Othello/Lind	50/100/200	115 kV	Queue Issues[4]
Lewiston/Clarkston	100/200	230 kV	<1
Northeast	10	115 kV	<1
Kettle Falls	12	115 kV	<1
Kettle Falls	24/100/124	115 kV	<20
Long Lake	68	115 kV	33
Monroe Street	80	115 kV	2
Post Falls	10	115 kV	<1
Cabinet Gorge	110	230 kV	<14

[2] https://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/GIP_Queue-V100_(public).pdf
[3] Cost estimates are in 2019 dollars and use engineering judgment with a 50 percent margin for error.
[4] This area of the system as several projects in the transmission request process, in total these projects exceed the local area's ability to integrate new resources and currently being studied.

Table 8.2: Third-Party Large Generation Interconnection Requests

Project	Size (MW)	Type	Interconnection Location	Proposed Date
#46	126	Wind	Big Bend (WA)	December 2018
#47	750	Wind	Colstrip 500kV (MT)	September 2018
#49	144	Wind	Big Bend (WA)	September 2018
#50	450	Pumped Hydro	Colstrip 500kV (MT)	December 2020
#51	300	Solar	Broadview (MT)	December 2020
#52	100	Solar	Big Bend (WA)	July 2020
#53	19.2	Solar	Big Bend (WA)	October 2018
#54	40	Solar	Big Bend (WA)	January 2019
#59	116	Solar & Storage	Big Bend (WA)	June 2021
#60	150	Solar & Storage	Lewiston/Clarkston	December 2022
#62	123	Wind	Big Bend (WA)	November 2021
#63	26	Hydro	Post Falls (ID)	February 2023
#66	71	Wood Waste	Kettle Falls (WA)	July 2023
#67	80	Solar	Big Bend (WA)	June 2023
#68	750	Wind	Colstrip 500kV (MT)	
#69	750	Wind	Colstrip 500kV (MT)	
#70	2.5	Storage	Liberty Lake (WA)	
#71	7	Solar	Big Bend (WA)	August 2020
#72	80	Solar	Big Bend (WA)	June 2021
#73	100	Solar	Big Bend (WA)	June 2020
#74	0.1	Storage	Spokane (WA)	
#76	200	Solar	Big Bend (WA)	December 2020
#77	5	Solar	Big Bend (WA)	December 2020
#79	5	Solar	Spokane (WA)	June 2020
#80	19	Solar	Spokane (WA)	June 2020
#81	94	Solar	Big Bend (WA)	June 2020
#82	600	Wind	Colstrip 500kV (MT)	December 2021
#83	300	Wind	Colstrip 500kV (MT)	October 2022
#84	5	Solar	Kettle Falls (WA)	August 2020
#85	5	Solar	Big Bend (WA)	August 2020
#86	20	Solar	Big Bend (WA)	December 2022
#90	5	Solar	Big Bend (WA)	August 2021
#94	5	Solar	Big Bend (WA)	August 2021
#95	600	Wind	Colstrip 500kV (MT)	December 2022
#96	400	Wind	Colstrip 500kV (MT)	December 2022
#97	150	Solar & Storage	Lewiston/Clarkston	December 2021
#98	80	Solar & Storage	Big Bend (WA)	December 2023
#99	200	Solar & Storage	Big Bend (WA)	December 2021
#100	100	Solar & Storage	Palouse (WA)	December 2021

Distribution Planning

Avista continually evaluates its distribution system. The distribution system consists of approximately 347 feeders covering 30,000 square miles, ranging in length from three to 73 miles. For rural distribution, feeder lengths vary widely to meet electrical loads resulting from the startup and shutdown of the timber, mining, and agriculture industries. The distribution evaluation determines if there are capacity limitations on the system to serve current and future projected load for each individual feeder. The analysis also includes whether or not the system meets reliability and level of service requirements including voltage and power quality. When a potential constraint is identified, an action plan is prepared and compared against other options, and then the best course of action is budgeted.

The primary role of electric distribution planning is to identify system capacity and service reliability constraints, and subsequently identify the best and lowest life-cycle cost solution. Traditionally this solution has centered on infrastructure upgrades such as poles, wire, and cable. New technologies are emerging that may impact system analysis, including storage, photovoltaic (solar), and demand response. As these alternatives mature and evolve they are likely to play a role in our investment portfolio either as primary solutions or capital deferment solutions. Avista has deployed several pilot projects with the intent of determining how best to meet customer needs and maintain a high degree of reliability now and in the future.

To properly evaluate each feeder for new technologies, load data and system data is required. Quality load data is not available for all Avista feeders beyond monthly data logs recording peak load and energy. Without detailed load data, evaluating new technologies is limited to portions of the system with the available data. Detailed data is required to validate whether new technologies solve current system constraint or just defers the constraint to a different time. Avista is currently installing automated meters for customers in Washington. When complete, the new meters will be able to collect additional data to improve the distribution planning process.

Currently, 195 of 347 feeders have three-phase SCADA (Supervisory Control and Data Acquisition) data available. Avista adds SCADA capability to additional feeders as resource and budgeting allow within our substation work schedule. As more demands beyond traditional capacity constraints and level of service requirements are placed on the grid, an increased amount of data is required to analyze and enhance the electric distribution system. As Avista implements its smart meters, much of the data can be compiled using the customer meter data alleviating the immediate need for SCADA related data collection.

New load forecasting techniques such as spatial load forecasting will be required. This new forecasting method uses GIS based information associated with feeder location and can help forecast specific feeder load growth taking into account zoning, demographics, land availability, and specific parcel information. With additional investment in both technology and human capital, Avista will be prepared to quickly study and implement new technologies on its distribution system.

Deferred Capital Investment Analysis

New technologies such as storage, photovoltaics, and demand response programs could help the electrical system by deferring or eliminating other investments. This is dependent on the new technology to solve system constraints and meet customer expectations for reliability. An advantage in using these technologies may be additional benefits incorporated into the overall power system. For example, storage can help meet overall power supply peak load needs, but it may also improve local reliability by providing voltage support and deferring capital investment on the distribution feeder or at the distribution substation.

This section discusses the analysis for determining the capital investment deferment value for distributed energy resources (DERs). Capital investment deferment is not the same for all locations on the system. Feeders differ by whether they are summer or winter peaking, the time of day the peaks occur, whether they are near capacity or not, and how fast loads are growing in the area. It is not practical to have an estimate for each feeder in an IRP, but it is prudent to have a representative estimate to include in the resource selection analysis.

For this IRP, Avista attempted a proof in concept of analyzing distribution feeder upgrades in the overall IRP analysis. The trial analysis includes distribution needs in the optimization of resources. Specifically, when solving for new resources to meet electric load, the optimization includes a requirement to solve a distribution feeder requirement. For this analysis Avista used the Huetter feeder in North Idaho. The model was given three options to solve the future shortfall in capacity. Two of the options were wire plans. The first is to add new regulators then add a new transformer later, the second is to add the new transformer now and not add regulators. Regulators allow for the deferral of a new transformer by three years. The regulators cost approximately $80,000, while a new transformer can cost up to $3 million. The third alternative is a non-wire alternative, adding the regulators then adding batteries with eight hours of storage capability rather than the new transformer. The storage resource could then alleviate a distribution requirement while also assisting the power system. Conducting this analysis in the PRiSM model includes both the benefits of the distribution system and the power system. The model found the first option of installing the regulators now, then later installing a new transformer was the preferred option.

Grid Modernization

In 2008, an Avista system efficiencies team of operational, engineering, and planning staff developed a plan to evaluate potential energy savings from transmission and distribution system upgrades. The first phase summarized potential energy savings from distribution feeder upgrades. The second phase, beginning in summer 2009, combined transmission system topologies with right sizing distribution feeders to reduce system losses, improve system reliability, and meet future load growth. The system efficiencies team evaluated several programs to improve urban and rural distribution feeders. The programs consisted of the following system enhancements:

- Conductor losses;
- Distribution transformers;
- Secondary districts; and
- Volt-ampere reactive compensation.

The analysis combined energy losses, capital investments, and reductions in O&M costs resulting from the individual efficiency programs under consideration on a per feeder basis. This approach provided a means to rank and compare the energy savings and net resource costs for each feeder. Building on the 2009 effort, a 2013 study assessed benefits of distribution feeder automation for increased efficiency and operability. The Grid Modernization Program (GMP) combines work from system performance studies and provides Avista's customers with refreshed system feeders with new automation capabilities across the Company's distribution system. Table 8.3 shows the feeders currently planned for rebuild and their associated energy savings. The total energy savings from both re-conductor and transformer efficiencies for all completed feeders is approximately 1,206 MWh annually.

The GMP charter ensures a consistent approach to how Avista addresses each project. This program integrates work performed under various Avista operational initiatives, including the Wood Pole Management Program, the Transformer Change-Out Program, the Vegetation Management Program, and the Feeder Automation Program. The Distribution GMP includes replacing undersized and deteriorating conductors, and replacing failed and end-of-life infrastructure materials including wood poles, cross arms, fuses, and insulators. It addresses inaccessible pole alignment, right-of-way, under-grounding, and clear-zone compliance issues for each feeder section, as well as regular maintenance work including leaning poles, guy anchors, unauthorized attachments, and joint-use management. This systematic overview enables Avista to cost-effectively deliver a modernized and robust electric distribution system that is more efficient, easier to maintain, and more reliable for our customers.

Table 8.3: Planned Feeder Rebuilds

Feeder	Area	Year Complete	Annual Energy Savings (MWh)
BEA12F2	Spokane, WA	2020	269
ROS12F5	Spokane, WA	2021	152
SIP12F4	Spokane Valley, WA	2022	283
M15514	Moscow, ID	2023	245
MIS431	Kellogg, ID	2023	257
		Total	**1,206**

Merchant Transmission Rights

Avista transmission rights are in two parts. The first is Avista's owned transmission. This transmission is used by Avista's merchant department to serve Avista customers or is available to other utilities or power producers. The merchant department dispatches and controls the power generation for Avista. FERC separates utility functions between merchant and transmission to allow for fair access to the Avista transmission system. Avista also purchases transmission from other utilities to serve customers. Specifically this is transmission procured on the behalf of the merchant side of Avista. The merchant group has transmission rights with BPA, PGE, and a few smaller local electric utilities. Table 8.4 shows the rights of the Merchant's transmission. Avista also must show a load serving need to reserve transmission on the Avista owned transmission system to ensure equitable access to the transmission capacity. Appendix E shows the projected need and future use of the Avista transmission system.

Table 8.4: Merchant Transmission Rights

Counterparty	Path	Quantity (MW)	Expiration
BPA	Lancaster to John Day	100	6/30/2026
BPA	Coyote Springs 2 to Hatwai	97	8/1/2026
BPA	Coyote Springs 2 to Benton	50	8/1/2026
BPA	Garrison to Hatwai	196	8/1/2026
BPA	Coyote Springs 2 to Vantage	125	10/31/2022
BPA	Townsend to Garrison	210	9/30/2027
PGE	John Day to COB	100	12/31/2023
Northern Lights	Dover to Sagle	As needed	n/a
Kootenai Electric	Rockford to Worley	As needed	12/31/2028

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9. Supply-Side Resource Options

Avista evaluates several generation supply-side resource options to meet future resource deficits. The resource categories evaluated for this IRP include upgrading existing resources, building and owning new generation facilities, and contracting with other energy companies. This section describes resource options Avista considers in the 2020 IRP. The options are mostly generic, as actual resources are typically acquired through competitive processes. This process may yield resources that differ in size, cost, and operating characteristics due to siting, engineering, or financial requirements.

Section Highlights

- Solar, wind, and other renewable resource options are modeled as Purchase Power Agreements (PPA) instead of utility ownership.
- Upgrades to Avista's hydroelectric, natural gas and biomass facilities are included as resource options.
- Future competitive acquisition processes might identify different technologies available to Avista.
- Renewable resource costs assume no extensions of current state and federal tax incentives.
- Avista models several energy storage options including pumped storage hydro, lithium-ion, vanadium flow, zinc bromide flow, liquid air, and hydrogen.

Assumptions

Avista models only commercially available resources with well-known costs and generation profiles priced as if Avista developed and owned the generation or acquires generation from Independent Power Producers (IPPs) with a Purchase Power Agreement (PPA). Resources modelled as PPAs include pumped storage, wind, solar, geothermal, and nuclear resources. Avista modeled these resource types as PPAs since IPPs are able to financially capture tax benefits for these resources earlier, which reduces the cost to customers. Other resource options assume utility ownership include natural gas-fired combined cycle combustion turbines (CCCT), simple cycle combustion turbines (SCCT), natural gas-fired reciprocating engines, energy storage, biomass, hydroelectric upgrades, hydroelectric contracts, and thermal unit upgrades. Upgrades to coal-fired units are not included or considered in the IRP analysis. Modeling resources as PPA or ownership does not preclude the utility from acquiring new resources in other manners, but serves as an appropriate cost estimate for the new resources. Several other resource options described later in the chapter are not included in the PRS analysis, but we discuss them as potential resource options since they may appear in a request for a future resource acquisition.

It is difficult to accurately model potential contractual arrangements with other energy companies as an option in the plan, but such arrangements may offer a lower customer cost when a competitive acquisition process is completed. Avista plans to use a competitive RFP process for all resource acquisition where possible to ensure the lowest cost resource is acquired for our customers; although other acquisition process may yield better pricing on a case-by--case basis – especially for existing resources for shorter time periods. When evaluating upgrades to existing facilities Avista uses the IRP, RFPs, and market intelligence to determine and validate its assumptions to pursue the upgrade. Upgrades typically require competitive bidding processes for contractors and equipment when available.

The costs of each resource option do not include the transmission expenses described in Chapter 8 – Transmission & Distribution Planning, all cost are considered at the bus bar. Avista excludes these costs in this chapter to allow for cost comparison as resource costs at specific locations depend on the location chosen. When Avista evaluates the resources for selection in the IRP, it includes these costs. All costs are levelized by discounting nominal cash flows by a 6.68 percent-weighted average cost of capital approved by the Idaho and Washington Commissions in recent rate case filings. All costs in this section are in 2020 nominal dollars unless otherwise noted. All cost and characteristic assumptions for generic resources and how PPA pricing is calculated is available in Appendix F.

Avista relies on several sources including the NPCC, press releases, regulatory filings, internal analysis, developer estimates, and Avista's experience with certain technologies for its generic resource assumptions. For this IRP, Avista also engaged Black and Veatch to perform a reasonability test of our resource assumptions. This report is available Appendix G.

Levelized resource costs illustrate the differences between generator types. The values show the cost of energy if the plants generate electricity during all available hours of the year. In reality, plants do not operate to their maximum generating potential because of market and system conditions. Costs are separated between energy in $/MWh, and capacity in $/kW-year, to better compare technologies[1]. Without this separation of costs, resources operating very infrequently during peak-load periods would appear more expensive than baseload CCCTs, even though peaking resources are lower total cost when operating only a few hours each year. Avista levelizes the cost using the production capability of the resource. For example, a natural gas turbine is available 92 to 95 percent of the time when taking into account maintenance and forced outage rate. Avista divides the cost by the amount of megawatt hours the machine is capable of producing. For resources that are available but may not have the fuel available, such as a wind project, the resource costs are divided by its expected production.

Tables at the end of this section show incremental capacity, heat rates, generation capital costs, fixed O&M, variable costs, and peak credits for each resource option.[2] Table 9.1 compares the levelized costs of different resource types over a 30-year asset life.

[1] Storage technologies use a $ per kWh rather than $ per kW because the resource is both energy and capacity limited.
[2] Peak credit is the amount of capacity a resource contributes at the time of system one-hour peak load.

Natural Gas-Fired Combined Cycle Combustion Turbine

Natural gas-fired CCCT plants provide reliable capacity and energy for a relatively modest capital investment. The main disadvantages of a CCCT are generation cost volatility due to reliance on natural gas, unless utilizing hedged fuel prices, and the emission of carbon dioxide. This IRP models CCCTs as "one-on-one" (1x1) configurations, using hybrid air/water cooling technology and zero liquid discharge. The 1x1 configuration consists of a single gas turbine with a heat recovery steam generator (HRSG) and a duct burner to gain more generation from the steam turbine. The plants have nameplate ratings between 250 MW and 350 MW each depending on configuration and location. A two-on-one (2x1) CCCT plant configuration is possible with two turbines and one HRSG, generating up to 650 MW. Avista would need to share a 2x1 plant to take advantage of the modest economies of scale and efficiency of a 2x1 plant configuration due to its large size relative to Avista's needs.

Cooling technology is a major cost driver for CCCTs. Depending on water availability, lower-cost wet cooling technology could be an option, similar to Avista's Coyote Springs 2 plant. However, absent water rights, a more capital-intensive and less efficient air-cooled technology may be used. For this IRP, Avista assumes water is available for plant cooling based on its internal analysis, but only enough for a hybrid system utilizing the benefits of combined evaporative and convective technologies.

This IRP models five types of CCCT plants, ranging in sizes from 235 MW to 480 MW as 1x1 configuration. Avista reviewed many CCCT technologies and sizes, and selected these plants due to the range in size to have the potential for the best fit for the needs of Avista's customers. If Avista pursues a CCCT, a competitive acquisition process will allow analysis of other CCCT technologies and sizes at both Avista's preferred location and at other locations. It is also possible Avista could acquire an existing combined cycle resource from one of the many in the Pacific Northwest.

The most likely location for a new CCCT is in Idaho, mainly due to Idaho's lack of an excise tax on natural gas consumed for power generation, a lower sales tax rate relative to Washington, and no state taxes or fees on the emission of carbon dioxide.[3] CCCT sites likely would be on or near our transmission system to avoid third-party wheeling costs. Another advantage of siting a CCCT resource in Avista's Idaho service territory is access to relatively low-cost natural gas on the GTN pipeline. Avista previously secured a site with these potential connection points in the event it needs to add additional capacity from either a CCCT or another technology.

Combined cycle technology efficiency has improved since Avista's current generating fleet entered service with higher heating value heat rates as low as 6,500 Btu/kWh for a larger facility and 6,600 for smaller configurations. Duct burners can add additional capacity with heat rates in the 7,200 to 8,400 btu/kWh range.

[3] Washington state applies an excise tax on all fuel consumed for wholesale power generation, the same as it does for retail natural gas service, at approximately 3.875 percent. Washington also has higher sales taxes and has carbon dioxide mitigation fees for new plants.

The anticipated capital costs for the two modeled CCCTs, located in Idaho on Avista's transmission system with AFUDC on a greenfield site range between $905 to $1,529 per kW in 2020 dollars. A likely configuration of the modern technology is $1,052 per kW. These estimates exclude the cost of transmission and interconnection. Table 9.1 shows levelized plant cost assumptions split between capacity and energy for both the combined cycle options discussed here and the natural gas peaking resource discussed in the next section. The costs include firm natural gas transportation, fixed and variable O&M, and transmission. Table 9.2 summarizes key cost and operating components of natural gas-fired resource options. With competition from alternative technologies and the need for additional flexibility for intermittent resources is likely to put downward pressure on future CCCT costs.

Natural Gas-Fired Peakers

Natural gas-fired SCCTs and reciprocating engines, or peaking resources, provide low-cost capacity capable of providing energy as needed. Technological advances and their simpler design relative to CCCTs allow them to start and ramp quickly, providing regulation services and reserves for load following and variable resources integration. Natural gas-fired peakers have similar benefits and costs as CCCTs.

This IRP models frame, hybrid-intercooled, reciprocating engines, and aero-derivative peaking resource options. The peaking technologies have different load following abilities, costs, generating capabilities, and energy-conversion efficiencies. Table 9.2 shows cost and operational characteristics based on internal engineering estimates and reviewed by Black & Veatch. All peaking plants assume 0.5 percent annual real dollar cost decreases and forced outage and maintenance rates. The levelized cost for each of the technologies is in Table 9.1.

Firm natural gas fuel transportation is an electric reliability issue with FERC and the subject of regional and extra-regional forums. For this IRP, Avista continues to assume it will not procure firm natural gas transportation for peaking resources and will use its current supply or short-term transportation for peaking needs. Firm transportation could be necessary where pipeline capacity becomes scarce during utility peak hours. Where non-firm transportation options become inadequate for system reliability, four options exist: contracting for firm natural gas transportation rights, purchasing an option to exercise the rights of another firm natural gas transportation customer during times of peak demand, on-site fuel oil, and liquefied natural gas storage.

Table 9.1: 2020 Natural Gas-Fired Plant Levelized Costs

Plant Name	Total $/MWh	$/kW-Yr (Capability)	Variable $/MWh	Winter Capacity (MW)
Advanced Large Frame CT	48	118	35	220
Advanced Small Frame CT	62	163	43	186
Frame/Aero Hybrid CT	54	159	35	106
Large Reciprocating Engine Facility	52	165	33	189
Small Reciprocating Engine Facility	54	183	33	47
Modern Small Frame CT	58	172	39	49
Aero CT	59	195	36	45
1x1 Advanced CCCT	46	151	29	362
1x1 Modern CCCT	48	171	27	306

Table 9.2: Natural Gas-Fired Plant Cost and Operational Characteristics

Item	Capital Cost with AFUDC ($2020/kW)	Fixed O&M ($2020/kW- yr)	Heat Rate (Btu/ kWh)	Variable O&M ($/MWh)	Total Project Size (MW)	Total Cost (Mil$-2020)
Advanced Large Frame CT	679	2.08	9,148	2.08	245	166
Advanced Small Frame CT	969	5.20	11,049	3.12	84	81
Frame/Aero Hybrid CT	1,031	3.12	8,856	3.12	92	95
Large Reciprocating Engine Facility	1,055	7.28	8,296	3.12	184	194
Small Reciprocating Engine Facility	1,162	13.53	7,891	4.16	91	106
Modern Small Frame CT	1,088	4.16	9,931	2.60	48	52
Aero CT	1,239	6.24	10,335	2.60	45	56
1x1 Modern CCCT	1,052	14.57	6,668	3.12	413	434
1x1 Advanced CCCT	979	17.69	6,586	3.90	308	302

Wind Generation

Wind resources benefit from having no direct emissions or fuel costs, but they are not typically dispatchable to meet load. Avista is modeling four wind location options in the plan: Montana, Eastern Washington, Columbia Basin, and offshore. Configurations of facilities are changing given transmission limitations in the region and the benefits of tax credits, low construction prices, and the potential for storage. These factors allow for sites being built with higher capacity levels than the transmission system can integrate. When the wind facilities generate additional MWh above the physical transmission limitations[4], the generators typically feather or could store energy using on site energy storage. At this time, Avista is not modelling wind with onsite storage or wind facilities with greater output capabilities then can be integrated on the transmission system.

Onshore winds capital costs in 2020, including AFUDC, are $1,568 per kW for Washington on-system projects, off-system projects including Oregon and Montana are $1,458 per kW, and off-shore wind is $3,569 per kW. The annual fixed O&M costs of $36.40 per kW-year for on-shore wind and $93.60 per kW-year for offshore wind. Fixed O&M does not include indirect charges to account for the inherent variation in wind generation, often referred to as wind integration. The cost of wind integration depends on the penetration of wind in Avista's balancing authority and the market price of power.

Wind capacity factors in the Northwest range between 25 and 40 percent depending on location and in the 40 to 50 percent range in Montana and offshore locations. This plan assumes Northwest wind has a 37 percent average capacity factor. A statistical method, based on regional wind studies, derives a range of annual capacity factors depending on the wind regime in each year (see stochastic modeling assumptions for details).

This IRP also estimates potential costs for offshore wind. Offshore wind has the potential for higher capacity factors (50 percent), but costs are higher. At the time of this IRP, developers have not been offering an offshore product in the Pacific Northwest. The pricing and costs are estimates based on other proposals in North America.

As discussed above, levelized costs change substantially due to capacity factor, but can change even more from tax incentives and the ownership structure of the facility. Table 9.3 shows the nominal levelized prices with different start dates for each location. These price estimates assume the facility is acquired using a 20-year PPA with a flat pricing structure, but also includes the intermittent generation integration charge for the first 100 MW to Avista's system and includes costs associated with passing the cost of the PPA to customers, excise taxes, commission fees, and uncollectables. These costs do not include the transmission costs for either capital investment or wheeling purchases. If a PPA is selected in Avista's resource strategy (Chapter 11), the model assumes the PPA will extend through the 25-year time period.

[4] In the event transmission is limited due to contractual reasons; an additional option is to buy non-firm transmission to move the power.

Table 9.3: Levelized Wind Prices ($/MWh)

Year	On-System Wind	Off-System Wind	Montana Wind	Off-Shore Wind
2020	38	34	20	90
2021	37	33	19	90
2022	42	38	25	97
2023	49	45	31	103
2024	56	52	38	110
2025	69	65	51	123
2026	70	67	51	125
2027	71	68	52	126
2028	72	68	53	127
2029	72	69	53	129
2030	73	70	54	130
2031	74	71	55	131
2032	75	72	56	133
2033	76	73	56	134
2034	77	75	58	136
2035	78	76	59	137
2036	80	78	60	138
2037	81	79	61	140
2038	83	81	63	141
2039	85	83	64	143
2040	86	85	65	144

Photovoltaic Solar

Photovoltaic (PV) solar generation technology costs fell substantially over the last several years partly due to low-cost imports and from demand driven by renewable portfolio standards. Solar systems are now built with more generating capacity than the transmission interconnect limit to take advantage of increased energy produced throughout the year when only limited hours of the year occur when full production is produced. Some systems, also have storage connected to the system to help with integration of intermittent production, store excess energy to avoid curtailment, or shift energy to higher priced hours. Solar plus storage has an advantage, compared to other renewable systems, because storage may qualify for investment tax credits when paired with solar as long as the stored energy is from solar production. Since both systems use DC power, they can utilize the same power inverters. Other renewable resources may not benefit from this tax provision because production rather than capital spending drive the tax credits. It is possible future solar incentives will be similar to the Production Tax Credit rather than the ITC.

Avista models four potential solar systems, the first is an on-system solar facility in 25 MW (AC) increments, but modelled as a facility with at least 100 MW to take advantages of economies of scale. It is Avista's understanding the solar costs can change significantly depending on size; to address this issue, a smaller 5 MW (AC) on-system is also included. The third solar option includes a facility to be wheeled to Avista in higher solar production areas such as southern Idaho or Oregon. Although if and when Avista attempts to acquire solar energy any location is acceptable to participate in the RFP, but transmission charges and availability will be used to determine if the project(s) to move forward.

Solar capital costs have been rapidly declining, even with increasing tariffs costs. Technology improvements such as bi-facial panels make solar more efficient at delivering energy per square meter. For this IRP, larger systems assume a cost of $1,156 per kW (AC) for a single axis tracking system; by 2030, these costs are expected to rise to $1,255 per kW and $1,455 per kW by 2040. While these costs increase in nominal dollars, real solar costs are likely to fall. Smaller systems assume premium prices due to a lack of economies of scale with a price of $1,399 per kW in 2030 with similar price changes as larger systems in the future. The cost to operate solar depends on the size of the facility and location due to property taxes and lease payments; given these costs vary, Avista assumes $8 per kW-year for larger systems and $10 per kW-year for smaller systems.

Table 9.4 shows the levelized prices for 20-year flat PPA with additional costs to integrate the first 100 MW of intermittent generation, excise taxes, commission fees, and uncollectables. These costs do not include the transmission costs either for investment or wheeling purchases. The prices also assume current phase-out of federal tax credits by 2024.

Table 9.4: Levelized Solar Prices

Year	On-system	Southern NW	On-system-small facility
2020	38	34	50
2021	38	34	50
2022	37	33	48
2023	38	34	49
2024	48	43	63
2025	49	44	64
2026	50	44	64
2027	51	45	65
2028	51	45	66
2029	52	46	67
2030	52	47	68
2031	53	47	69
2032	54	48	69
2033	54	48	70
2034	55	49	71
2035	56	49	72
2036	56	50	73
2037	57	51	74
2038	58	51	75
2039	59	52	76
2040	59	53	76

Solar Energy Storage (Lithium-ion Technology)

As previously discussed, storage paired with solar takes advantage of federal tax credits, lowers transmission costs, shifts energy deliveries, helps manage intermittent generation, uses common equipment, increases peak reliability, and prevents energy oversupply. Avista must study each potential benefit to see its value and the amount of storage duration is cost effective for each potential project. While the solar plus storage system receives tax incentives (approximately six years) it must be only supplied with solar energy. This limits the value of the storage asset due to its inability to assist with larger system variations.

Lithium-ion technology prices are falling and will likely continue to fall. Avista estimates the additional cost for more hours of storage in Table 9.5 for solar PPAs. Avista modeled one, two, and four-hour durations; although, 15 to 30 minutes will be considered if the technology is limited to assist with intermittent generation rather than reliability. Avista's experience with solar generation from its 19.2 MW Adams-Neilson PPA show significant energy variation due to cloud cover. Avista will identify in future IRPs the cost of this variability on different size projects in the event of future acquisition. For this IRP, Avista considers savings for integration and resource adequacy but due to the complexity and range of potential configurations, requires the utility to continue this analysis as Avista's system changes with less thermal resources and more intermittent resources. In addition, Avista's modeling of solar plus storage allows the storage device to use grid power as it may after six years.

Table 9.5: Storage Cost w/ Solar System ($/kW-month)

Year	One-Hour	Two-Hour	Four-Hour
2020	9.0	10.3	12.9
2021	7.3	8.3	10.4
2022	6.9	7.8	9.8
2023	6.5	7.4	9.3
2024	7.2	8.2	10.2
2025	6.8	7.8	9.7
2026	6.4	7.3	9.1
2027	6.2	7.1	8.9
2028	6.1	6.9	8.7
2029	5.9	6.8	8.5
2030	5.8	6.7	8.3
2031	5.7	6.5	8.2
2032	5.6	6.4	8.0
2033	5.5	6.3	7.8
2034	5.4	6.1	7.7
2035	5.3	6.0	7.5
2036	5.2	5.9	7.4
2037	5.1	5.9	7.3
2038	5.1	5.8	7.2
2039	5.0	5.7	7.1
2040	4.9	5.6	7.0

Stand Alone Energy Storage

Energy storage resources are gaining significant traction as a resource of choice in the western U.S., although energy storage does not create energy (it shifts it from one period to another in exchange for a portion of the energy stored). Avista is modelling several energy storage options including pumped hydro storage hydro, lithium-ion, vanadium flow, zinc bromide flow, liquid air, and hydrogen. In addition to the technology differences, Avista also considers different energy storage durations for each technology. Pricing for energy storage is also rapidly changing due to the technology advancements currently taking place. In addition to changing pricing for existing technologies, new technologies are entering the storage space. For example, iron flow batteries became a commercial technology while producing this IRP. The rapid change in pricing and new available technologies justifies the need for frequent IRP analysis on an every other year basis.

Another challenge with storage is in the pumped hydro technology where costs and storage duration can be substantially different depending on the geography of the proposed project. Storage is also gaining attention to address transmission and distribution expansion, where the technology can alleviate conductor overloading and short duration load demands rather than adding physical line/transformation capacity. Avista considers this as a benefit here, but discusses it further in Chapter 8- Transmission and Distribution Planning

The storage costs discussed in this chapter are shown as the levelized cost for the duration capability of the storage resources. This means the cost of capital and operations are levelized then divided by the duration in kilowatt-hours of the resource. Storage cannot be shown in $ per MWh as with other generation resources because they do not create energy, only store it. This analysis shows the cost differences between the technologies but does not consider the efficiency of the storage process or the cost of the energy stored. This analysis is performed in the resource selection process.

Pumped Hydro

The most prolific energy storage technology currently in both the U.S. and the world is pumped hydro storage. This technology requires the use of two or more water reservoirs with different elevations. When prices or load are low, water is pumped up to a higher reservoir and released during higher price or load periods. Over time this technology may help with meeting system integration issues from intermittent generation resources. Currently only one of these projects exist in the northwest and several more are in various stages of the permitting process. An advantage with pumped hydro is the technology has long service lives and is technology Avista is familiar with as a hydro generating utility. The greatest disadvantages are large capital costs and long-permitting cycles.

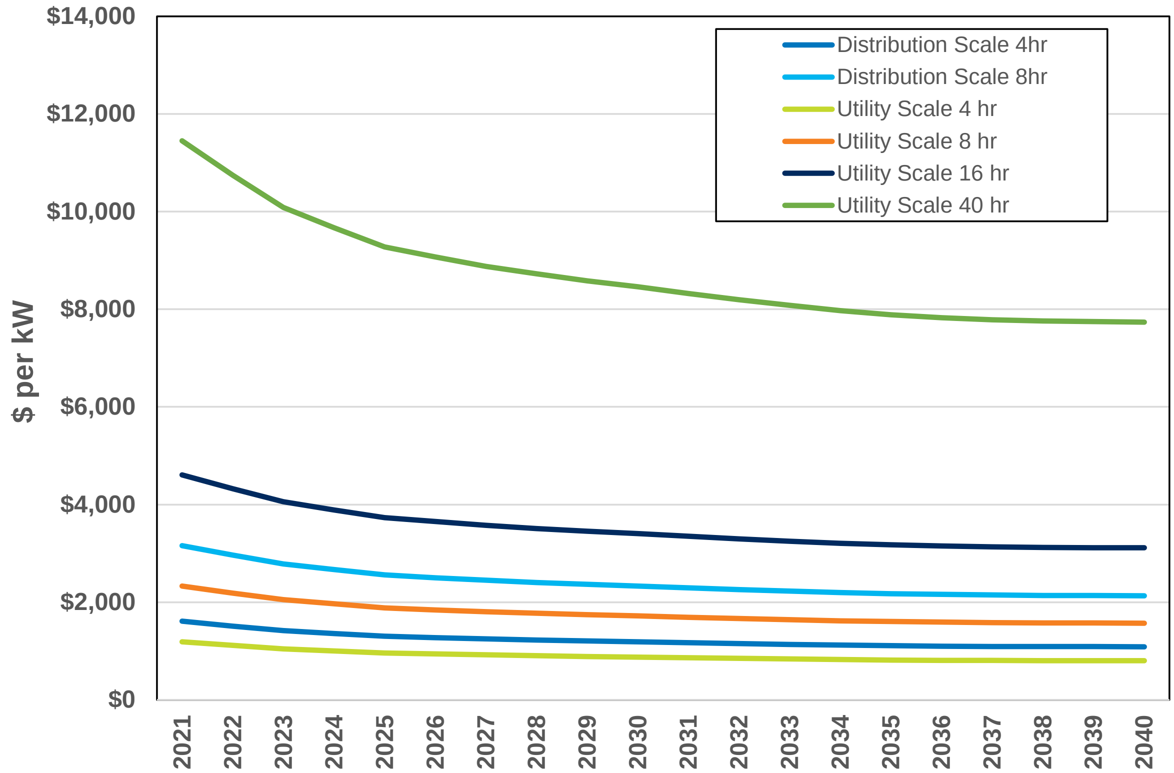
The technology has good round trip efficiency rates (Avista assumes 81 percent). When projects are developed, they are designed to utilize the amount of water storage in each reservoir and the generating/pump turbines are sized for how long the capacity needs to operate. For the IRP resource analysis, Avista models the technology with six different durations: 8 hours, 12 hours, 16 hours, 24 hours, 40 hours, and 80 hours. These durations are the amount of hours the project can run at full capacity. Modeling different duration times are required because in an energy-limited system, Avista requires resources with enough energy to provide reliable power over an extended period in addition to single hour peaks. This study uses the ELCC analysis discussed later in the chapter. Avista bases its pricing for pumped hydro using a PPA financing methodology with fixed and variable payments. The price estimate for pumped hydro is a 2020 capital cost of $2,936 per kW with $15.60 per kW of Fixed O&M per year. This results in a 2020 PPA price of $22.28 per kW-month and $5.00 per MWh of generation. These prices are generic in nature, and certain projects in the northwest have lower estimates. Avista choose to also model a lower price point of $12.50 per kW-month in the event a project has lower costs due to favorable siting or permitting. With these two price points considered, Avista believes these two price points provide enough range in pricing. A future RFP will determine pumped hydro's actual pricing and availability. Avista is conducting internal studies of the availability of pumped storage in or around its service territory. These studies may provide additional resource options in future IRPs or RFP processes.

Lithium-ion

As discussed before, lithium-ion technology is one of the fasted growing segments of the energy storage space. When coupled with solar, both tax advantages and economies of scope can reduce the upfront pricing. This discussion focuses on using energy storage as a stand-alone resource rather than coupled with solar. Stand-alone lithium-ion assumes a utility owned asset for modeling purposes, but it could be acquired as a PPA format as well with two 10-year cycles for a 20-year life. Fixed O&M costs are included in pricing for replacements cells to maintain the storages energy conversion efficiency.

The lithium-ion technology is an advanced battery using ionized lithium atoms in the anode to separate their electrons. This technology can carry high voltages in small spaces making it a preferred technology for mobile devices, power tools, and electric vehicles. The large manufacturing sector of the technology drives prices lower and permits utility scale projects.

Figure 9.1: Lithium-ion Capital Cost Forecast



Avista models six conceptual stand-alone configurations for lithium-ion batteries. Two small-scale sizes (3 MW) with four and eight hour durations for modeling the potential for use on the distribution system and four larger systems (25 MW) including four and eight hour durations, but also theoretical 16 and 40 hour configurations. Pricing for this technology was set in the winter 2018/2019 using publically available pricing and forecasts, as well as review by Black & Veatch. Figure 9.1 show the forecast for each of the sizes and durations considered. Avista classifies the 4-hour battery as the standard technology with a capital cost of $1,188 per kW or $297 per kWh for 2021. Fixed O&M costs are also expected to decline; Avista assumes for the 4-hour technology an annual cost of $44.30 per kW year in 2020 and by 2030 fall to $30.70 per kW-year.

Storage technology is often displayed in many methods to illustrate the cost because it is not a traditional capacity resource. Table 9.6 below shows levelized cost per kWh for each configuration. This calculation factor levelizes the cost for the capital, O&M, and regulatory fees over 20 years divided by the capacity’s duration. These costs do not consider the variable costs, such as energy purchases.

Table 9.6: Lithium-ion Levelized Cost $/kWh

Year	Distribution Scale 4 hour	Distribution Scale 8 hour	Utility Scale 4 hour	Utility Scale 8 hour	Utility Scale 16 hour	Utility Scale 40 hour
2020	287	563	212	415	822	2,041
2021	276	541	204	399	789	1,961
2022	266	522	196	385	761	1,891
2023	258	505	190	372	737	1,831
2024	251	493	185	363	719	1,787
2025	246	482	182	356	704	1,749
2026	242	475	179	350	694	1,723
2027	239	469	176	346	684	1,700
2028	237	464	174	342	677	1,681
2029	234	459	173	338	670	1,664
2030	232	455	171	335	664	1,649
2031	230	451	170	332	658	1,635
2032	228	447	168	330	653	1,622
2033	227	444	167	327	648	1,610
2034	225	441	166	325	644	1,600
2035	224	439	165	324	641	1,592
2036	223	437	164	322	638	1,585
2037	222	435	164	321	635	1,579
2038	221	434	163	320	633	1,573
2039	221	432	163	319	631	1,568
2040	220	431	162	318	629	1,562

Flow Batteries

This IRP models two types of flow batteries, vanadium and zinc bromide. Other technologies are beginning to show up in the marketplace recently, including iron. Flow batteries have the advantage over lithium-ion as they do not degrade over time and have longer operating lives. The technology consists of two tanks of liquid solutions that flow adjacent to each other past a membrane and generate a charge by moving electrons back and forth during charging and discharging. Avista assumes acquisition size of 25 MW of capacity with 4-hours in duration for each technology.

Capital costs are $1,319 per kW for the vanadium in 2020 and costs fall 38 percent by 2030. Zinc bromide's capital cost are $1,385 per kW, in 2020 falling by 44 percent by 2030. Fixed O&M costs are $58 per kW-year for vanadium and $66 per kW-year for zinc bromide, these cost increase with inflation. Round-trip efficiency for the vanadium is 70 percent and zinc bromide is 67 percent. Given Avista's experience with vanadium flow batteries, these efficiency rates are highly dependent on the battery's state of charge and how quickly the system is charged or discharged. Table 9.7 shows the levelized cost per kWh of capacity.

Table 9.7: Flow Battery Levelized Cost $/kWh

Year	Vanadium	Zinc Bromide
2020	230	247
2021	217	228
2022	205	211
2023	205	197
2024	188	194
2025	188	191
2026	187	191
2027	186	191
2028	186	191
2029	186	191
2030	186	191
2031	186	192
2032	186	192
2033	187	193
2034	187	194
2035	188	195
2036	189	196
2037	191	198
2038	192	200
2039	194	202
2040	196	204

Liquid Air

A new technology with promise to provide long duration and long service life is liquid air storage. This is similar to compressed air storage but rather than compressing the air, the air is cryogenically frozen and stored into a tank to increase storage duration capability. The conversion process requires a liquefier to liquefy the air for storage. It is possible to use waste heat from existing natural gas-fired turbines to increase the efficiency of liquefying the air molecules. This increases round-trip efficiencies from 65 percent to 75 percent. After the air is stored, it can be later used by pushing the air through an air turbine.

Liquid air has not been widely used in the electric sector but uses common technology from other industries requiring liquefaction of other gases. This experience in the technology gives promise as a new technology that should benefit from short commercialization periods. Avista assumes a 25 MW capacity with 400 MWh hours of storage (16 hours). Another advantage of this technology is the ability to add storage capacity by adding additional tanks and using the same turbine and liquefaction systems.

Avista estimates liquid air storage capital costs at $1,457 per kW (2020 dollars) and increasing with inflation rather than declining as the technology is not expected to reduce in real terms due to its using mature technology. Fixed O&M is $25 per kW-year and carry's a $3.00 per MWh variable charge. The levelized cost of the storage is estimated to be $215 per kWh for 2020 and future years increase with inflation.

Hydrogen/ Fuel Cell

The idea of using hydrogen in the energy sector has been an option for the distant future for some time. Avista recognizes this technology as an avenue for long-duration energy storage with the potential to store power to continuously run for up to several days. The technology behind this storage concept is to use electric power to electrolyze water into hydrogen; the hydrogen would be stored in tanks and then converted back to power (and water) later using a fuel cell. This process would result in a 34 percent round trip efficiency. The ability to store hydrogen into tanks similar to liquid air means long duration times can be obtained. Hydrogen technologies are getting significant R&D in the transportation and other sectors and may reduce its costs or increase its efficiency. It is also possible the transportation and other sectors could utilize the electric power system to create a cleaner form hydrogen to offset gasoline, diesel, propane, or even natural gas. The concept of offsetting natural gas led Avista to engage Black and Veatch to provide Avista's Natural Gas IRP process estimates for renewable hydrogen options. The assumptions and discussion are a result of this study.

The main source of hydrogen today uses methane-reforming techniques to remove hydrogen from natural gas or coal. This technology is primarily used in the oil and gas industries, but results in similar levels of greenhouse gas emissions from the combustion of the underlying fuels. If the hydrogen could be obtained from "clean" energy through electrolysis, the amount of greenhouse gas emissions can be greatly reduced. If renewable energy prices fall and there is an available water supply the operating cost of creating hydrogen could also fall, but capital costs would remain steady.

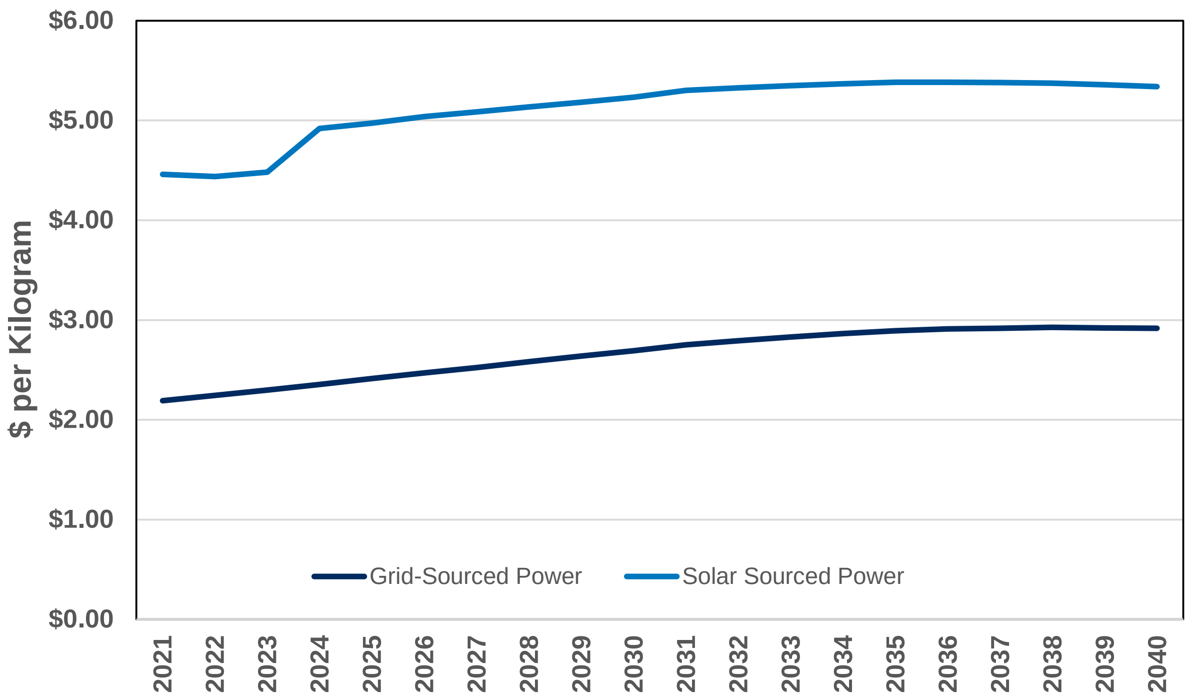
Converting hydrogen back into power would require a hydrogen fuel cell. There are many fuel cell technologies on the market. Avista started Avista Labs which was ultimately sold to Plug Power which is a fuel cell manufacturer. There are also other fuel cell technologies, which convert natural gas into power such as Bloom Energy; but Avista is not modeling this conversion cycle, but rather hydrogen to power. It is also possible to co-fire hydrogen with natural gas; although Avista is not studying this alternative in this IRP.

Estimating the cost of the hydrogen storage concept requires multiple steps. For a four-hour duration project, the first step is the cost of the electrolysis system. For modeling purposes, the system would create 5,000 kilograms of hydrogen per day and have an upfront cost of $6.7 million or $1,340 per kilogram plus cost to operate the facility would add $443,000 per year. Additional costs would be required for the power, variable O&M, excise taxes, and fees. For modeling purposes, variable O&M is $0.06 per kilogram and the energy price will depend on if the electrolizer is powered using retail power or wholesale and when the power is consumed. For example, if an independent company was using electric power to create hydrogen for another end use the buyer of electric power would be paying retail rates; but if used as an electric energy storage, it would be treated similar to other storage technologies and be fueled by wholesale market prices.

The efficiency of power to hydrogen is 50 kWh per kg in 2020, but improves to 48 kWh per kg by 2030.

Figure 9.2 shows the levelized price per kilogram of grid powered hydrogen using the efficiency and costs discussed above. These costs do not consider transportation or remarketing costs and assume power sourced from the wholesale energy market. Avista estimated the cost per kilogram would be levelized for power sourced with only solar (off grid). These costs are higher than grid power due to lower utilization factors from only producing hydrogen when the sun was out. This concept could potentially be lower cost if technology can be configured to eliminate AC transformation. Thus, creating a pure DC closed loop system.

Figure 9.2: Wholesale Hydrogen Costs per Kilogram



The second step in the hydrogen storage concept is to convert the hydrogen back to power. For this conversion, a 25 MW fuel cell(s) would be assembled for a utility scale needs. Approximately 40 kWh of power will be created per kilogram of hydrogen, plus the hydrogen losses from its storage. The estimated capital cost for a fuel cell is $5,470 per kW with a four-hour storage vessel plus fixed O&M at $163 per kW-year. Table 9.7 shows the all-in levelized cost of hydrogen storage including the fuel cell for 4-hour, 16-hour, and 40-hour storage lengths. Based on this analysis, the all-in cost for hydrogen storage is much higher than other options. Hydrogen likely has a future, but its likely place will be in limited applications until costs decrease, such as distributed solar with electrolysis for transportation related systems requiring frequent fueling.

Table 9.8: Hydrogen Storage and Fuel Cell Levelized Cost $/kWh

Year	4-Hour	16-Hour	40-Hour
2020	861	870	881
2021	864	872	883
2022	866	874	886
2023	868	877	888
2024	870	879	890
2025	873	882	893
2026	884	893	904
2027	895	904	915
2028	906	915	927
2029	918	927	938
2030	929	938	950
2031	948	957	969
2032	967	976	988
2033	986	996	1,008
2034	1,006	1,016	1,028
2035	1,026	1,036	1,048
2036	1,046	1,056	1,069
2037	1,067	1,078	1,090
2038	1,089	1,099	1,112
2039	1,110	1,121	1,134
2040	1,133	1,143	1,157

Woody Biomass Generation

Woody biomass generation projects use waste wood from lumber mills or forest management. In the generation process, a turbine converts boiler-created steam into electricity. A substantial amount of wood fuel is required for utility-scale generation. Avista's 50 MW Kettle Falls Generation Station consumes over 350,000 tons of wood waste annually or 48 semi-truck loads of wood chips per day. It typically takes 1.5 tons of wood to make one megawatt-hour of electricity, the ratio varies with the moisture content of the fuel. The viability of another Avista biomass project depends on the availability and cost of the fuel supply. Many announced biomass projects fail due to lack of a long-term fuel source.

Based on market analysis of fuel supply and expected use of biomass facilities, a new facility could be envisioned as a wood-fired peaker. With high levels of intermittent renewable generation, a wood-fired peaker could be constructed to generate during low renewable output months or days. The capital cost for this type of facility would be $2,500 per kW plus O&M amounts of $150 per kW-year for fixed costs and $3.17 per MWh of variable costs (2020 dollars). The levelized cost per MWh is $111 per MWh for a 2020 project.

Geothermal Generation

Geothermal energy provides predictable capacity and energy with minimal carbon dioxide emissions (zero to 200 pounds per MWh). Some forms of geothermal technology extract steam from underground sources to run through power turbines on the surface while others utilize an available hot water source to power an Organic Rankine Cycle installation. Due to the geologic conditions of Avista's service territory, no geothermal projects are likely to develop locally. Geothermal energy struggles to compete economically due to high development costs stemming from having to drill several holes thousands of feet below the earth's crust. Ongoing geothermal costs are low, but the capital required for locating and proving a viable site is significant. In Avista's last RFP, one geothermal project was bid, and this led Avista to reconsider this option as a possible resource to include in the IRP. While a project was bid, it does have the hurdles previously discussed. The IRP estimates a future geothermal PPA is $80 per MWh in 2020 at the busbar.

Nuclear

Avista did not include nuclear plants as a resource option in prior IRPs given the uncertainty of their economics, regional political issues with the technology, U.S. nuclear waste handling policies, and Avista's modest needs relative to the size of modern nuclear plants. Nuclear resources could be in Avista's future only if other utilities in the Western Interconnect incorporate nuclear power in their resource mix and offer Avista an ownership share or if cost effective small-scale nuclear plants become commercially available.

The viability of nuclear power could change as national policy priorities focus attention on decarbonizing the nation's energy supply. The limited amount of recent nuclear construction experience in the U.S. makes estimating construction costs difficult. Cost projections in the IRP are from industry studies, recent nuclear plant license proposals, and the small number of projects currently under development. Modular nuclear design could increase the potential for nuclear generation by shortening the permitting and construction phase, and making these traditionally large projects a better fit the needs of smaller utilities. Given this possibility, Avista included an option for small scale nuclear power. The estimated cost for nuclear per MWh on a levelized basis in 2030 is $123 per MWh assuming capital costs of $4,518 per kW (2020 dollars) as a PPA.

Other Generation Resource Options

Resources not specifically included as options in this IRP include cogeneration, landfill gas, anaerobic digesters, and central heating districts. This plan does not model these resource options explicitly but continues to monitor their availability, cost, and operating characteristics to determine if state policies change or the technology becomes more economically available.

Exclusion from the PRS analysis does not necessarily exclude non-modeled technologies from Avista's future portfolio. The non-modeled resources can compete with resources identified in the PRS through competitive acquisition processes. Competitive acquisition processes identify technologies to displace resources otherwise included in the IRP strategy. Another possibility is acquisition through PURPA. PURPA provides developers the ability to sell qualifying power to Avista at set prices and terms.[5]

[5] Rates, terms, and conditions are available at www.avistautilities.com under Schedule 62.

Landfill Gas Generation

Landfill gas projects generally use reciprocating engines to burn methane gas collected at landfills. The Northwest has developed many landfill gas resources. The costs of a landfill gas project depend on the site specifics of a landfill. The Spokane area had a project on one of its landfills, but it was retired after the fuel source depleted to an unsustainable level. Much of the Spokane area no longer landfills its waste and instead uses the Spokane Waste to Energy Plant. Nearby in Kootenai County, Idaho, the Kootenai Electric Cooperative developed the 3.2 MW Fighting Creek Project. Using publically available costs and the NPCC estimates, landfill gas resources are economically promising, but are limited in their size, quantity, and location. Many landfills are considering cleaning the landfill gas to create pipeline quality gas due to falling wholesale electric market prices. This form of renewable gas has become an option for natural gas utilities to offer a renewable gas alternative to customers. This form of gas and the duration of the supply depends on the on-going disposal of trash, otherwise the methane could be depleted in seven to ten years.

Anaerobic Digesters (Manure or Wastewater Treatment)

The number of anaerobic digesters is increasing in the Northwest. These plants typically capture methane from agricultural waste, such as manure or plant residuals, and burn the gas in reciprocating engines to power generators. These facilities tend to be significantly smaller than most utility-scale generation projects, at less than five megawatts. Most facilities are located at large dairies and cattle feedlots. A survey of Avista's service territory found no large-scale livestock operations capable of implementing this technology.

Wastewater treatment facilities can host anaerobic digesting technology. Digesters installed when a facility is initially constructed helps the economics of a project significantly, although costs range greatly depending on system configuration. Retrofits to existing wastewater treatment facilities are possible but tend to have higher costs. Many projects offset energy needs of the facility, so there may be little, if any, surplus generation capability. Avista currently has a 260 kW wastewater system under a PURPA contract with a Spokane County wastewater facility. Anaerobic digesters may opt to clean the gas to make to pipeline quality to offer a clean gas alternative.

Small Cogeneration

Avista has few industrial customers with loads significantly large enough to support a cogeneration project. If an interested customer was inclined to develop a small cogeneration project, it could provide benefits including reduced transmission and distribution losses, shared fuel, capital, and emissions costs, and credit toward Washington's EIA efficiency targets.

Another potentially promising option is natural gas pipeline cogeneration. This technology uses waste-heat from large natural gas pipeline compressor stations. Few compressor stations exist in Avista's service territory, but the existing compressors in our service territory have potential for this generation technology. Avista has discussed adding cogeneration with pipeline owners, but no project has been determined feasible.

A big challenge in developing any new cogeneration project is aligning the needs of the cogenerator with the utility need for power. The optimal time to add cogeneration is during the retrofit or creation of an industrial process, but the retrofit may not occur when the utility needs new capacity. Another challenge to cogeneration within an IRP is estimating costs when host operations drive costs for a particular project. The best method for the utility to acquire this technology is through the PURPA process or in a future RFP.

Coal

The coal generation industry is at a crossroads. In many states, like Washington, new coal-fired plants are extremely unlikely due to emission performance standards and the shortage of utility scale carbon capture and storage projects. The risks associated with future carbon legislation and projected low natural gas and renewables costs make investments in this technology highly unlikely. It is possible in the future there with be permanent carbon sequestration technology at price points to compete with alternative fuels. Avista will continue to monitor this development for future IRPs.

Heating Districts

Historically heating districts were preferred options to heat city centers. This concept relies on a central facility to either create steam or hot water then distribute via a pipeline to buildings to provide heat for their end use of space and water heating. Historically, Avista provided steam for downtown Spokane using a coal-fired steam plant. This concept is still used in many cities in the U.S. and Europe including Seattle, WA. Developing new heating districts requires the right circumstances, partners, and long-term vision.

These requirements recently came together in a new concept of central heating districts being tested by a partnership between Avista and McKinstry in the Spokane University District called the Eco-District. The Hub facility will contain a central energy plant. It can generate, store, and share thermal and electrical energy with a combination of heat pumps, boilers, chillers, thermal, and electrical storage. The Hub will control all electric consumption for the campus and balance this against the needs of both the development and the grid. Future buildings within the district will be served by the Hub's central energy plant, expanding the district's shared energy footprint. A part of the Eco-District development will involve studying the costs and benefits of this configuration. The success of the district will determine how it will be implemented in the future for Avista's customers.

Bonneville Power Administration

For many years, Avista received power from the Bonneville Power Administration (BPA) through long-term contract as part of the settlement from WNP-3. Most of the BPA's power is sold to preference customers or in the short-term market. Avista does not have access to power held for preference customers but does engage BPA on the short-term market. Avista has two other options for procuring BPA power. The first is using the New Resource NR rate. BPA's power tariff outlines a process for utilities to acquire power from BPA using this rate for one year at a time. As of the publishing of this IRP, the NR rate is

$79.80 per MWh[6]. Since this offering is short-term and variable, Avista does not consider it as a viable long-term option for planning purposes, but it is a viable alternative for short-run capacity needs. The other option to acquire power from BPA is to solicit an offer. BPA is willing to provide prices for periods of time when it believes it has excess power or capacity. This process would likely parallel an RFP process for future capacity needs.

Existing Resources Owned by Others

Avista purchased long-term energy and capacity from regional utilities in the past, specifically the Public Utility Districts in Mid-Columbia region. Avista contracts are currently discussed in Chapter 4, but extensions or new agreements could be formed. It is also possible in the event other utilities are long on capacity to develop agreements to strengthen Avista's capacity versus load positon. Since these potential agreements are based on existing assets, prices depend on future markets. Avista is modeling for this IRP the possibility of an up to 75 MW extension of existing agreements, but the cost and actual quantities available are unknown. Avista could acquire or contract for energy and capacity of other existing facilities without long term agreements. Avista anticipates these resources will be offered into future RFPs.

Renewable Natural Gas

Avista did not model the option to use renewable natural gas (RNG) for electric generation in this IRP. RNG is methane gas sourced from waste produced by dairies, landfills, wastewater treatment plants and other facilities. The amount of RNG is limited by the output of the available processes. The amount of greenhouse gas emissions the RNG offsets differs depending upon the source of the gas and the duration of the methane abatement used. Avista considers the cost-effective use of this fuel type in its Natural Gas IRP and believes its best use is to reduce emissions from the direct use of natural gas rather than use it as a fuel in natural gas-fired turbines due to higher efficiency in end use in customer's homes.

Hydroelectric Project Upgrades and Options

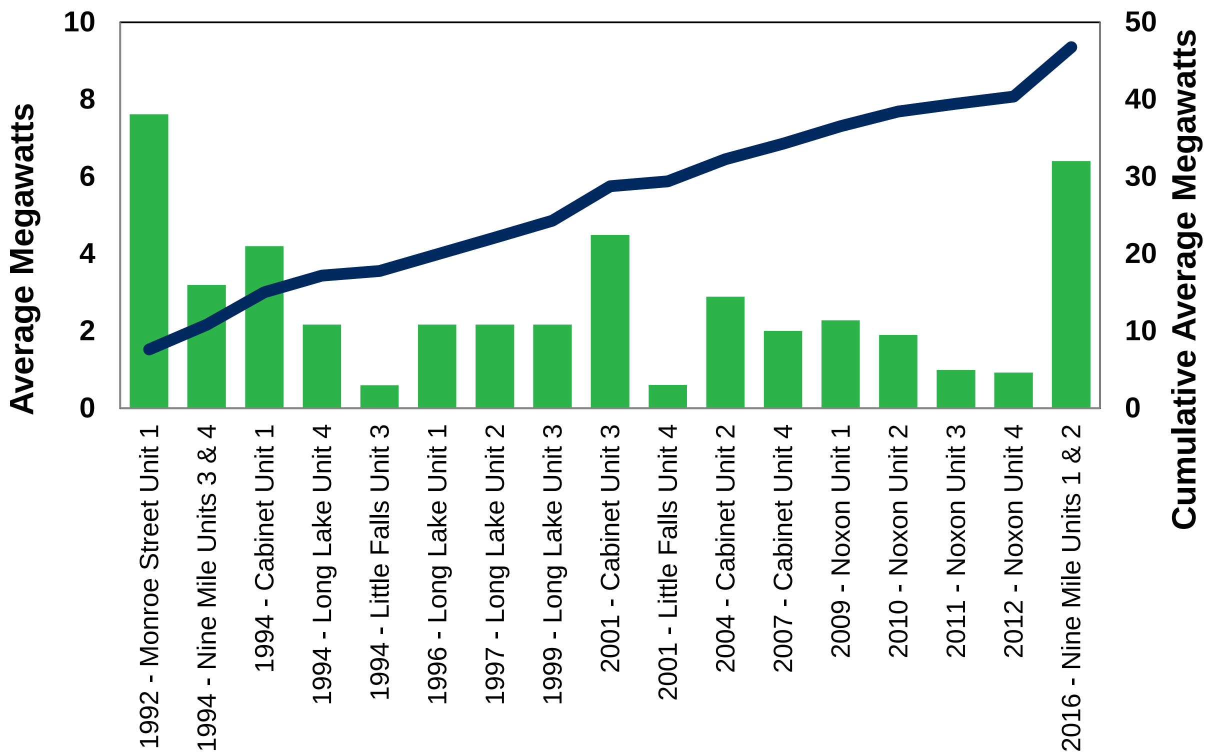
Avista continues to upgrade its hydroelectric facilities as shown in Figure 9.3. The latest hydroelectric upgrade added ten megawatts to the Nine Mile Falls Development in 2016. Avista added 46.8 aMW of incremental hydroelectric energy between 1992 and 2016. Upgrades completed after 1999 can qualify for the EIA, thereby reducing the need for additional renewable energy options. Further, any upgrade can qualify for CETA if it meets the requirements as a clean energy resource.

Construction of the Spokane River hydroelectric project occurred in the late 1800s and early 1900s, when the priority was to meet then-current loads. The developments therefore do not capture a majority of river flows. In 2012, Avista reassessed its Spokane River Project to evaluate opportunities to capture more of the streamflow. The goal was to develop a long-term strategy and prioritize potential facility upgrades. Avista evaluated five of the six Spokane River developments and estimated costs for generation upgrade options. Each upgrade option should qualify for the EIA renewable energy goal. These

[6] https://www.bpa.gov/Finance/RateInformation/Pages/Current-Power-Rates.aspx.

studies were part of the 2011 and 2013 IRP Action Plans and results appear below. Each of these upgrades are major engineering projects, taking several years to complete and requiring major changes to the FERC licenses and the project's non-consumptive water rights. The upgrades will compete against other renewable options when more renewables are required or developed as Avista considers the most effective management plans for these existing projects.

Figure 9.3: Historical and Planned Hydro Upgrades



Post Falls

At the time of publishing the 2017 IRP, the Post Falls project was undergoing an analysis to determine the best course of action to maintain the facility. Two primary options were proposed. The first option is to replace existing equipment with similar size. The second option is to increase the capacity of the project by eight megawatts. Within this IRP modeling process, the PRiSM model can choose to upgrade the facility in 2027. Upgrading the facility would increase generating capacity by 4.5 aMW and increase winter peak generation by 3.8 MW for an additional cost above replacing with in-kind equipment.

Long Lake Second Powerhouse

Avista studied adding a second powerhouse at Long Lake over 30 years ago by using the small arch or saddle dam located on the south end of the project site. This project would be a major undertaking and require several years to complete, including major changes to the Spokane River FERC license and water rights. In addition to providing customers with a clean energy source, this project could help reduce total dissolved gas levels by reducing spill at the project and providing incremental capacity to meet peak load growth.

The 2012 study considered three alternatives. The first replaces the existing four-unit powerhouse with four larger units totaling 120 MW, increasing capacity by 32 MW. The other two alternatives develop a second powerhouse with a penstock beginning from a new intake structure downstream of the existing saddle dam. One powerhouse option was a single 68 MW turbine project. The second was a two-unit 152 MW project. The best alternative in the study was to add the single 68 MW unit. Table 9.9 shows upgrade costs and characteristics. Avista will need to refine this study for future analysis as the existing machinery in the powerhouse approach their end of life.

Monroe Street/Upper Falls Second Power House

Avista replaced the powerhouse at its Monroe Street development on the Spokane River in 1992. There are three options to increase its capacity. Each would be a major undertaking requiring substantial cooperation with the City of Spokane to mitigate disruption in Riverfront and Huntington parks and downtown Spokane during construction. The upgrade could increase plant capacity by up to 80 MW. To minimize impacts on the downtown area and the park, a tunnel drilled on the east side of Canada Island could avoid excavation of the south channel to increase streamflow to the new powerhouse. A smaller option would add a second 40 MW Upper Falls powerhouse, but this option would require south channel excavation. A final option would add a second Monroe Street powerhouse for 44 MW. All project options were removed for this IRP due to the disruption to the Riverfront Park and the downtown area. Avista may reconsider this analysis in future partnership with the City of Spokane.

Cabinet Gorge Second Powerhouse

Avista is exploring the addition of a second powerhouse at the Cabinet Gorge development site to mitigate total dissolved gas and produce additional electricity. A new 110 MW underground powerhouse would benefit from an existing diversion tunnel around the dam built during original construction. This resource does not add any peak capacity credit due to the water right limitations of the license. The resource only creates additional energy during spring runoff.

Table 9.9: Hydroelectric Upgrade Options

Resource	Monroe Street/Upper Falls	Long Lake	Cabinet Gorge
Incremental Capacity (MW)	80	68	110
Incremental Energy (MWh)	237,352	202,592	161,571
Incremental Energy (aMW)	27.1	23.1	9.2
Peak Credit (Winter/ Summer)	31/0	100/100	0/0
Capital Cost ($2020 Millions)	$171	$165	$260
Levelized Energy Cost ($2020/MWh)	$92	$84	$196

Thermal Resource Upgrade Options

For the last several IRPs, Avista investigated opportunities to add capacity at existing facilities. These projects have been implemented when cost effective. Avista is modeling three potential options at Rathdrum CT and an option at Kettle Falls Generating State. No costs are presented in this section, as pricing is sensitive to third-party suppliers, but presents an overview of the concepts. Estimated cost are including the portfolio modeling discussed in Chapter 11.

Rathdrum CT Supplemental Compression

Supplemental compression is a new technology developed by PowerPhase LLC that increases airflow through a CT compressor increasing machine output. This upgrade could increase Rathdrum CT capacity by 24 MW.

Rathdrum CT 2055 Uprates

By upgrading certain combustion and turbine components, the firing temperature can increase to 2,055 degrees from 2,020 degrees corresponding to a five MW increase in output.

Rathdrum CT Inlet Evaporation

Installing a new inlet evaporation system will increase the Rathdrum CT capacity by 17 MW on a peak summer day, but no additional energy is expected during winter months.

Kettle Falls Turbine Generator Upgrade

The Kettle Falls plant began operation in 1983. In 2025, the generator and turbine will be 42 years old and at the end of its expected life. At this time, Avista could spend additional capital and upgrade the unit by 12 megawatts rather than replace it with in-kind technology.

Intermittent Generation Costs

Intermittent generation resources such as wind and solar require other resources to help balance the unpredictable energy supply. This materializes in a cost by changing otherwise more efficient operations. For Avista this is challenging because the cost could be the difference of running stored water hours later compared to now. Avista began studying these costs on its system in 2007. This analysis created the methodology the ADSS model now uses to not only study the costs of the intermittent resources, but also better equips our real-time operations team in managing when to dispatch resources. For this IRP, wind will add approximately $5 per MWh in operating cost inefficiencies and solar $1.80 per MWh based on the 2007 study. Avista’s 2007 study is still relevant due to scenario analysis performed including pricing similar to prices of today along with a similar resource portfolio. With an EIM in place, Avista expects these costs to lower by 40 percent, this result was also part of the 2007 analysis when shorter trading blocks were studied. Avista believes these costs will increase with additional generation on the system and will need to study these issues in future IRPs when tools with sub-hourly modeling of Avista’s unique system are completed.

Another cost to consider when adding intermittent generation is the capacity value for reliability. Intermittent resources add additional load following requirements when operating in the event the resource loses power. For this additional requirement, Avista's ELCC studies require a 10 percent increase in held reserves of the produced energy each hour.

Ancillary Services Values

Many of the resources discussed in this chapter may provide benefits to the electrical system beyond traditional energy and capacity (for reliability). Some resources can provide reserve products such as Frequency Response or Contingency Reserves. Avista is required to hold generating reserves of 3 percent of load and 3 percent of on-line generation. This means resources need to be able to respond in 10 minutes in the event of other resources outages on the system. Within the reserve requirement, 22 MW must be held as frequency response to provide instantaneous response to correct system frequency variations. In addition to these requirements, Avista must also hold capacity to help control intermittent resources and load variance, this is referred to as load following and regulation. The shorter time steps minute-to-minute is regulation and longer time steps such as hour-to-hour is load following. Together these benefits consist of Ancillary Services for the purposes of this IRP.

Many types of resources can help with these requirements, specifically storage projects, natural gas peakers, and hydroelectric generation. The benefits these projects bring to the system greatly depend on many external factors including other "capacity" resources within the system, the amount of variation of both load and generation, market prices, market organization (i.e. EIM), and hydro conditions. Internal factors also play a role; these include the ability for the resource to respond in speed and quantity. Avista conducted a study on its Turner Energy Storage project along with the Pacific Northwest National Lab to clarify the operating restrictions of the technology. For example, if the battery is quickly discharged, the efficiency lowers and depending on the current state of charge the efficiency is also affected. These nuances make it more difficult to model in software systems.

Further, Avista needs to continue studying the benefits of energy storage by modeling additional scenarios including price, water year, and level of renewable penetration. It will also need to study the benefits of using a sub-hourly model. Avista is still developing the ADSS model to provide this complete analysis. In the fifth TAC meeting, Avista presented results from two studies regarding the potential analysis with the ADSS system. These analyses were completed using existing markets and showed the potential to provide benefits. Although, as Avista enters a future with additional on-system renewables and an EIM, these estimates will need to be revised. With this in mind, Table 9.10 outlines the assumed values for Ancillary Service benefits for new construction projects.

Table 9.10: Ancillary Services Value Estimates (2020 dollars)

Resource	$/kW-yr
Natural gas-fired CT/reciprocating engine	1.04
Lithium-ion battery	4.93
Lithium-ion battery connect to solar	1.50
Pumped hydro	4.93
Flow battery	1.56
Liquid Air	0.52

Resource ELCC Analysis

Avista conducted substantial research and time in studying the impact of resources effect on resource adequacy. Throughout this process, Avista learned that the quantity, location, and mixture of resources has a substantial effect on the benefit each resource can provide. For example, 4-hour duration storage can provide high levels of resource adequacy in small quantities because it has other resources to assist in its re-charging; but as its proportion gets larger, there is not enough energy to refill the storage device for later dispatch as shown in the E3 study for resource adequacy[7]. When coupled with renewable energy storage the combined resources may increase our resource adequacy, but this depends on how much energy can be stored and the amount produced in critical periods. Higher levels of penetrations for renewables may lower their effect on resource adequacy.

Avista used 1,000 simulations of Avista hydro, load, wind, and forced outage rates to estimate the contribution for different types of resources available to meet its peak. This is measured by the resources ability to lower Loss of Load Probability (LOLP) using the Avista Reliability Assessment Model (ARAM). The model is first simulated using a reliable system with a set of new natural gas-fired CTs to meet future load obligations. Then the gas turbines are removed and replaced with each of the resources in Table 9.11. The percentage shown in the table is the percent of natural gas turbines assumed the replacement resource would offset. After PRiSM selects the PRS, the specific resource selection is studied for LOLP. If not meeting the 5 percent LOLP metric due to intra reaction between the resources, the resulting/effective planning margin increases and a new strategy selected for comparison to the reliability metric.

[7] Appendix F, Resource Adequacy in the Pacific Northwest, page 54.

Table 9.11: Peak Credit

Resource	Peak Credit (percent)
Solar	2
Northwest wind	5
Montana wind[8]	36
Hydro w/ storage	100
Hydro run-of-river	31[9]
Storage 4 hr duration	15
Storage 8 hr duration	30
Storage 12 hr duration	58
Storage 16 hr duration	60
Storage 24 hr duration	65
Storage 40 hr duration	75
Storage 80 hr duration	95
Demand response	60
Solar + 4 hr Storage[10]	15
Solar + 2 hr Storage[11]	13

Other Environmental Considerations

Natural Gas Production and Transportation Greenhouse Gas Emissions

All generating resources have an associated emissions profile, either when it produces energy or when it was constructed. For this IRP Avista models associated emissions with the production of energy. Future IRPs may consider the emissions associated with the manufacturing and construction of the facility. Other potential studies could be from the indirect greenhouse gas emissions from biomass and coal production.

The only indirect greenhouse gas emissions resource studied in this plan is natural gas. Natural gas is assumed to emit 119 pounds of greenhouse gas emissions equivalent per dekatherm when including the other gases within the supply. In addition to those emissions, there could be upstream emissions from the drilling process and the transportation of the fuel to the plant also known as fugitive emissions. The Washington State customer's share of generation includes these potential emissions priced at the social cost of carbon for resource optimization. The additional emissions are 0.829

[8] Net of transmission losses.
[9] Based on Monroe Street 2nd Powerhouse.
[10] This resource assumes the storage resource may only charge with solar, this specific option was not modeled within the PRS and is shown as a reference only. Avista only modelled solar plus storage where the storage resource could be charged with non-solar as well to reflect long-term utility operations
[11] Avista limited solar plus storage to these two scenarios; many other options are likely including different durations and storage to solar ratios. Specific configurations would need to be studied to validate peak credits for those configurations

percent[12]. Avista sources its natural gas for power generation from the province of Alberta via the GTN pipeline and the province tracks these emissions. To account for these emissions, Avista is using a set of official reports as accounted for by the Canadian and United States governments. These 2017 reports were submitted to the National Energy Board (NEB) in Canada and PHMSA (Pipeline and Hazardous Materials Safety Administration) in the U.S. The reports carry penalties for falsehoods and are subject to review and audit.

There are three pipelines carrying natural gas from the Canadian production areas to the U.S. demand markets. The first is Nova Gas Transmission (NGTL) and it is the largest set of pipelines connected to the production fields bringing over eight billion dekatherms of energy to the market in 2017. Its carbon equivalent fugitive emissions are roughly five million tons or 0.767% of the overall energy produced. Foothills pipeline delivers 1.5 billion dekatherms of energy with a reported 0.678% fugitive emissions rate. Finally, Gas Transmission Northwest (GTN) is the backbone of supply of natural gas to our generation facilities and in 2017 alone delivered nearly eight hundred million dekatherms of volume with an emissions rate of 1.758%. As a system the overall emissions for 2017 is 1.164% and includes CO_2, CH_4 and N_2O emissions all converted to metric tons of carbon dioxide equivalents using 100-year Global Warming Potentials as found by the Intergovernmental Panel on Climate Change (IPCC). The IPCC is the United Nations body for assessing the science related to climate change. A summary of these figures and their sources can be found in Table 9.12:

Table 9.12: Natural Gas Fugitive Emissions

2017	Volume reported, Dth	Conversion of volume to tonnes CO_2 equivalent	Emissions reported, tonnes CO_2 equivalent	Percent
Nova Gas Transmission, NGTL[13]	8,202,460,151	435,430,053	3,341,551	0.767%
Foothills Pipeline, AB & SK[14]	1,527,266,974	81,075,425	549,489	0.678%
Gas Transmission Northwest, GTN[15]	794,764,490	42,190,311	741,635	1.758%
	10,524,491,615	558,695,789	4,632,676	0.829%

Greenhouse Gas Emissions for Storage Resources

Avista considers emissions from the acquisition of market power. As outlined in Chapter 10, the greenhouse gas emissions associated with power purchases is the average emission rate for the northwest area for this IRP. Avista conducted additional analysis to

[12] The IRP analysis included 0.783 percent for these emissions from Avista's draft analysis; the 0.829 percent number represents the final estimate.
[13] Volume: National Energy Board (NEB) Pipeline profiles data, neb-one.gc.ca; Emissions: Canadian GHG reporting program (GHGRP), climate-change.canada.ca.
[14] Volume: National Energy Board (NEB) Pipeline profiles data, neb-one.gc.ca; Emissions: Canadian GHG reporting program (GHGRP), climate-change.canada.ca.
[15] Volume: 2017 annual report to PHMSA, form 7100.2-1 (rev 10-2014), Part C, phmsa.dot.gov; Emissions: 2017 submission to EPA, epa.gov.

estimate the emissions associated with market purchases for energy storage resources. When power is stored from market power, it may have associated greenhouse gas emissions. Many other IRPs assume power stored is emission free, where its emissions are based on the source of the power stored. In a future where market purchases are used to store the power, the power will likely be assigned emissions from the market's emission intensity. Although the intensity of those emissions will differ from the market as the storage resources is only charging in certain periods. To understand this difference, Avista modeled the hourly emissions intensity of the northwest energy supply and matched those hours when a storage device was charging[16]. The results show when suppling a storage facility with market power will ultimately have lower emissions profiles than the overall energy market, this is because the market typically charges in lower price periods when more renewables are available. The amount of reduction as compared to the market depends on the duration of the storage resource, but on average storage emissions are 30 percent less than average market emission rates after 2030.

Other Environmental Considerations

There are other environmental factors involved when siting and operating power plants. Avista considers these cost in the siting process. For example, new hydroelectric projects or modifications to existing facilities must be made in accordance with their operating license, and if new facilities require operations outside this license, the license would reopen. When siting solar and wind facilities, developers must have approvals from local governing boards to make sure all laws and regulations are kept.

If Avista sites a new natural gas facility, it will have to meet state and local air requirements for its air permit. These requirements are at levels these governing bodies find fitting for their communities. At this time, Avista is not evaluating emissions costs outside of these considerations.

[16] This analysis uses the deterministic version of the expected cases market analysis.

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10. Market Analysis

The energy policy trajectory within the Western Interconnect is shifting toward clean generation. Several states, including Washington and California, passed 100 percent clean energy goals. These policy changes have a dramatic effect on the wholesale power market. Previous IRPs focused on carbon pricing methodologies driving wholesale power prices upward, but the new energy policies focusing rather on the quantities of renewable energy will likely push prices lower and cause more volatility in periods without significant renewable energy.

The market fundamental analysis is one of the most important factors to consider when selecting a resource strategy to serve Avista's customers over the next 25 years. Avista uses the forecast of future market conditions to optimize its resource portfolio options. The Company uses electric price forecasts to evaluate the net value of each option for comparative analysis between each resource type. The model tests each resource in the wholesale marketplace to understand its profitability, dispatch, fuel costs, emissions, curtailment, and other operating characteristics.

Section Highlights

- Solar and wind dominate future generation across the west, but natural gas, coal, and storage will keep the system resource adequate. By 2045, 96 percent of generation in the Pacific Northwest will be carbon free.
- Greenhouse gas emissions will fall to modern history lows due to expansion of renewables and coal plant retirements. By 2045, emissions will be 62 percent less than in 1990.
- The 20-year wholesale electric price forecast (2021-2040) is $26.44 per MWh. Expansion of renewables will lower mid-day prices, but evening and night prices will be at a premium compared to pricing in today's environment.
- Natural gas prices will remain low; the 20-year Stanfield natural gas forecast (2021-2040) is $3.47 per dekatherm.

Avista conducts the wholesale market analysis using the Aurora model developed by Energy Exemplar. This model includes generation resources, load estimates, and transmission links within the Western Interconnect. This chapter outlines the modeling assumptions and methodologies used for this IRP and includes Aurora's primary function of electric market pricing (Mid-Columbia for Avista), but also operating results from the analysis. The Expected Case is a forecast defined using the best available information on policies and resource costs under average conditions for renewable energy. This chapter also presents the results to four additional pricing scenarios.

Electric Marketplace

Avista simulates the Western Interconnect electric system for its IRP planning; shown as WECC[1] in Figure 10.1. The remaining areas of the U.S. and Canada are in separate electrical systems. The Western Interconnect includes the U.S. system west of the Rocky Mountains, plus two Canadian provinces and the northwest corner of Mexico's Baja peninsula.

The IRP's market simulation models each operating hour annually between 2021 and 2045. For each hour, the model simulates both load and generation dispatch for fifteen regional areas or zones within the west. Avista's load and a majority of its generation is in the Northwest zone identified in Table 10.1. Each of these zones include connections to other zones via transmission paths or links. These links allow generation trading between the zones and reflect operation constraints of the underlying system, but do not model the physics of the system as a power flow model. Avista focuses on the economic modeling capabilities of the Aurora platform to understand resource dispatch and market pricing effects. Avista's focus of this power system modeling is the resulting wholesale electric market price forecast for the Northwest zone or Mid-Columbia market place.

The Aurora model estimates its electric prices by using an hourly dispatch algorithm to match the load in each zone with the available generating resources. Resources selected to dispatch after considering its fuel availability, fuel cost, O&M cost, dispatch incentives/disincentives, and operating constraints. The electric price is the last generating resource required to meet area load marginal operating cost. The IRP uses these prices to value each of its resource (both supply and load side) options and select these as a least reasonable cost plan to meet its load obligations. Avista also conducts a stochastic analysis for its price forecasting where certain assumptions use a distribution of 500 potential inputs. For example, randomly drawing hydro conditions from an equal probability distribution of the 80-year hydro record.

The next several sections of this chapter discuss the assumptions used to derive the wholesale electric price forecast and resulting dispatch and greenhouse gas emissions profiles for the west for the 500 stochastic studies.

[1] WECC is an acronym for Western Electrical Coordinating Council. WECC coordinates reliability for the entire Western Interconnect.

Figure 10.1: NERC Interconnection Map

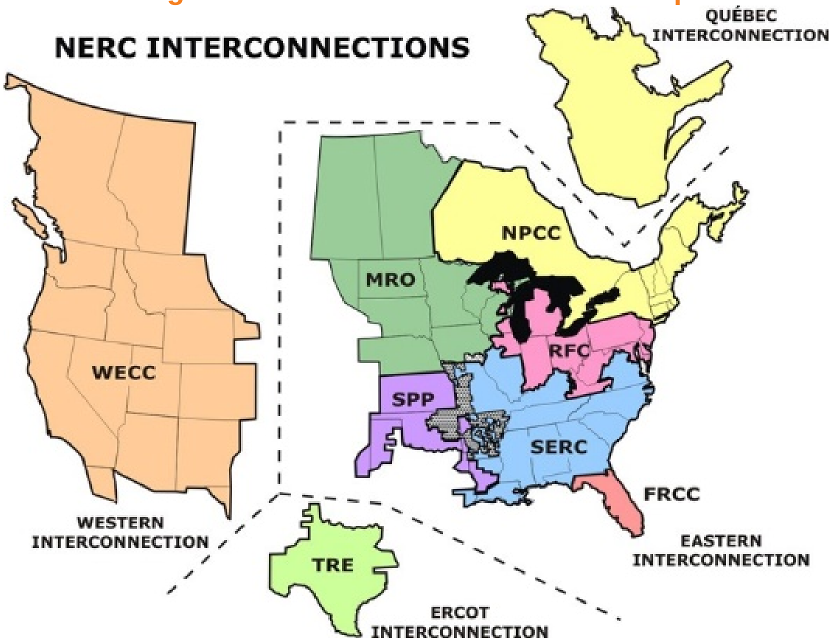


Table 10.1: AURORA^{XMP} Zones

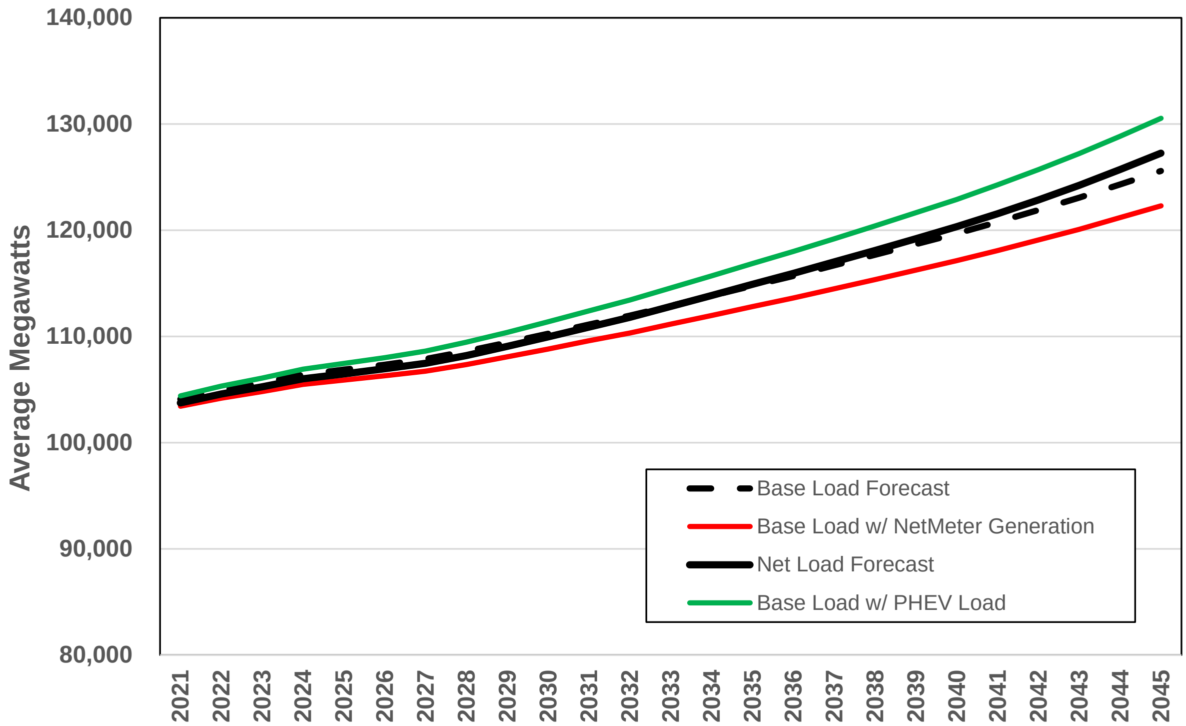
Northwest- OR/WA/ID/MT	Southern Idaho
Utah	Wyoming
Eastern Montana	Southern California
Northern California	Arizona
Central California	New Mexico
Colorado	Alberta
British Columbia	South Nevada
North Nevada	

Western Interconnect Loads

Each of the fifteen zones requires hourly load data for all 25 years of the forecast plus 500 different stochastic studies to account for weather variation. Future loads may not look like past loads from an hourly shape point of view due to the continual increase in electric vehicles and rooftop solar generation. Changes in energy efficiency, demand curtailment/demand response, population migration, and economic activity increase the complexity. While each of these drivers are important to the forecast of power pricing, it takes a large amount of analytical time to estimate or track these macro effects over the region for only power price modeling. Therefore, Avista uses the following methods to derive its regional load forecast for power price modeling.

To start the process, Avista relies on Energy Exemplar's demand forecast included with the software package. This forecast include an hourly load shape for each region along with annual changes to both peak and energy. The hourly load shape uses historical data each control area and the growth rates use publically available forecast information for each region. Figure 10.2 shows this base forecast below as the black dotted line. Over the full Western Interconnect, the load used in the model grows at 0.79 percent per year. Avista adjusts this forecast to account for changes in electric vehicle penetration and net-metered generation, such as rooftop solar. These adjustments change the forecast to approximately 0.85 percent per year. Electric Vehicle load grows at 12 percent per year and net-metered generation grows at 7 percent per year. Within the year, the hourly load shapes adjust to reflect charging patterns of both residential and commercial vehicle charging in addition to the majority of net-metered generation being modeled as fixed roof mount solar panels.

Figure 10.2: 25-Year Annual Average Western Interconnect Load Forecast



Regional Load Variation

Several factors drive load variability. The largest short-run driver is weather. Long-run economic conditions, like the Great Recession, tend to have a larger impact on the load forecast. IRP loads increase on average at the levels discussed earlier in this chapter, but risk analyses emulate varying weather conditions and base load impacts. Avista continues with its previous practice of modeling load variation using FERC Form 714 data from 2007 to 2015, the same assumption from the 2017 IRP[2]. These load variations change the loads for each of the 500 simulations of the electric price forecast. To maintain consistent west coast weather patterns, correlation factors between the Northwest and other Western Interconnect load areas represent how electricity demand changes together across the system. This method avoids oversimplifying Western Interconnect loads. Absent the use of correlations, stochastic models may offset changes in one variable with changes in another, virtually eliminating the possibility of broader excursions witnessed by the electricity grid. The additional accuracy from modeling loads this way is

[2] 2017 Electric IRP pages 10-15 to 10-16.

crucial for understanding wholesale electricity market price variation. It is vital for understanding the value of peaking resources and their use in meeting system variation.

Generation Resources

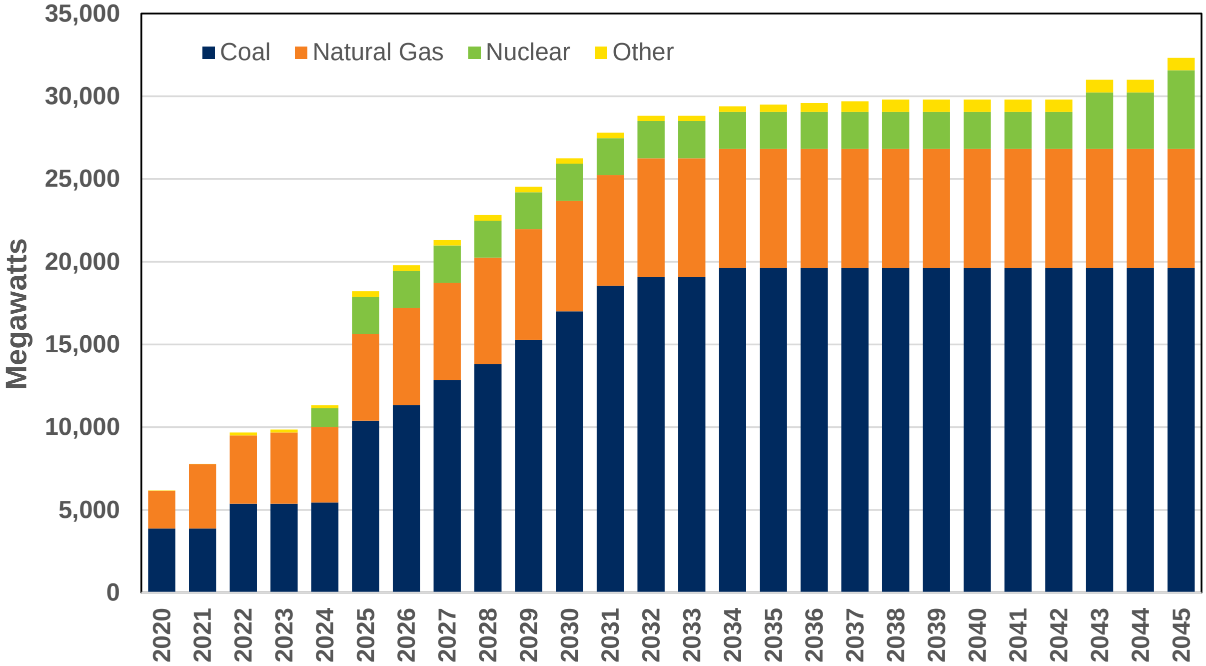
The Aurora model needs a forecast of generation resources to compare and dispatch against the load forecast for each hour. A generation availability forecast includes the following mean components:

- Resources currently available;
- Resource retiring;
- New resources for capacity;
- New resources for renewable energy compliance; and,
- Fuel prices, fuel availability, and operating availability of each resource within the system.

Energy Exemplar, the vendor of Aurora, provides a database of existing generating resources. The database includes location, size, and estimated operating characteristics for each resource. When a resource has a publicly scheduled retirement date or is part of a provincial phase-out plan, these resources are retired for modeling purposes. Avista does not include estimated retirements of any resources. Rather, plants that become less economic in the forecast will dispatch fewer hours. Specifically, the northwest includes a number of expected coal plant retirements including Boardman, Colstrip[3], North Valmy, and Centralia. Figure 10.3 shows the total retirements included in the electric price forecast. Approximately 20,000 MW of coal, 7,000 MW of natural gas, 5,000 MW of nuclear, and 750 MW of other resources including biomass, hydro, and geothermal are known to retire by the end of 2045.

[3] This IRP modeled Colstrip Units 1 and 2 to be offline at the end of 2019 and one of the remaining units is modeled to go offline at the end of 2025.

Figure 10.3: Cumulative Resource Retirement Forecast



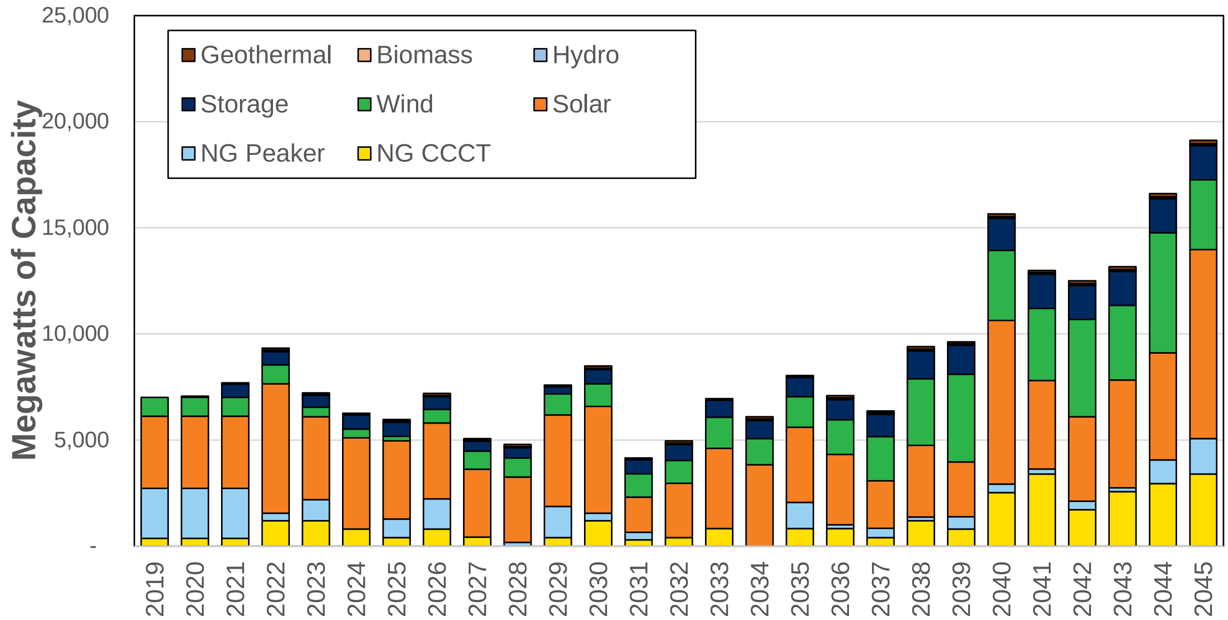
New Resource Additions

In order to meet future load growth, clean energy goals, and to replace retired generation, a new generation forecast must include resources to meet peak load and renewable portfolio standards. Furthermore, some states include emission constraints, or require emission pricing for new resource additions. Avista uses a resource adequacy based forecast for new resource additions, along with data estimates provided by third party consultants. The process begins with a forecast of new generation by resource type from the third party consultant. Consultants with multiple clients and dedicated staff can research new resource costs and operating characteristics with greater efficiency then Avista on likely resource construction in the west, especially in areas where Avista has no presence or local market knowledge. The next step in this process adjusts the clean energy additions to reflect changes in state policies for additional renewable energy. The last step runs the model for 500 simulations to see if each area can meet a resource adequacy test. The goal is for each area to serve all load in at least 475 of the 500 iterations.

Figure 10.4 shows the added generation included in this forecast. This forecast includes approximately 250 GW of added resources including 110 GW of supply side solar, 50 GW of wind, 30 GW of natural gas combined cycle CTs, 24 MW of storage[4], 20 GW of natural gas CTs, and 4 GW of other resources including hydro, biomass, and geothermal.

[4] Storage energy to capacity ratio averages 3 hours in 2021 and increases to 6 hours by 2045. This change is to reflect technological advances in duration of batteries or other storage technologies.

Figure 10.4: Western Generation Resource Additions (Nameplate Capacity)



Within the northwest region[5], additional resources are required to meet both resource adequacy and meet clean energy requirements (both mandates and customer choice) through 2045. Resource adequacy requires an estimated 5 GW of additional natural gas turbines and 3 GW of storage. Regional clean energy targets require 28 GW of solar, 14 GW of wind, and 2 GW of other renewable technologies.

Generation Operating Characteristics

Avista makes a number of changes to the resources available to serve future loads to account for Avista's specific expectations of the marketplace such as fuel prices and to reflect potential variation of resource supply such as wind and hydro generation.

Natural Gas Prices

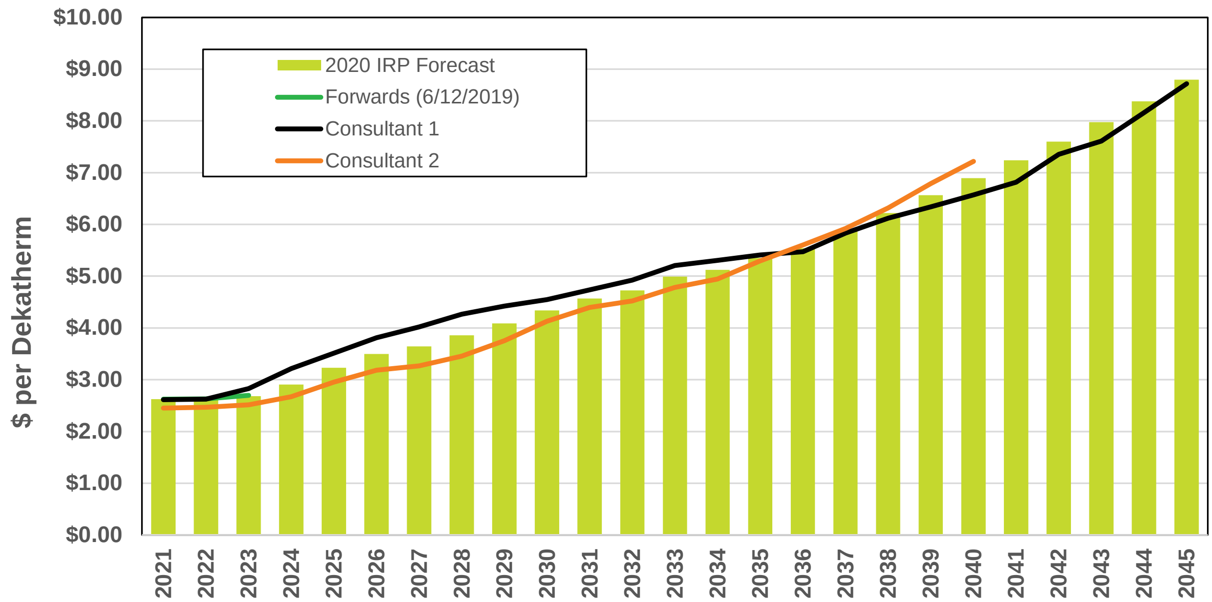
Historically, natural gas prices were the greatest indicator of electric market price forecasts. In fact, between 2003 and 2019 the R^2 between natural gas and on-peak Mid-Columbia electric prices is 0.89, indicating a strong correlation. This is due to the fact the natural gas-fired generation facilities were typically the marginal resource in the northwest with the exception of times when hydro generation was high due to water flow. In addition, natural gas generation met 30 percent of the load in the Western Interconnect in 2018. With the large increases in intermittent renewable energy from solar and wind in the west, the number of hours where natural gas-fired facilities will set the marginal price is likely to decline.

For modeling purposes, Avista uses monthly natural gas prices for dispatch and changes these prices based on a distribution of prices for each of the 500 stochastic forecasts. The forecasts begins with the Henry Hub forecast. Henry Hub is the location used for

[5] The northwest includes Washington, Idaho, Oregon, and Montana.

most natural gas transactions in North America for price hedging. Since Avista is not equipped with fundamental forecasting tools, nor is it able to track all natural gas market dynamics, it uses three sources for these forecasts. The first source is forward market prices as of June 12, 2019. The model uses these prices exclusively for 2021, but Avista lowers the forward market price weight compared to the other two sources to 75 percent in 2022, 50 percent in 2023, 25 percent and 2024, and zero thereafter. The other two sources of forecasted Henry Hub prices are from two consultants with the capability to follow the supply and demand changes of the industry. The model weights these two forecasts evenly in the forward estimate through 2040. Between 2040 and 2045, prices escalate at the last two years growth rate. Figure 10.5 shows each of the components included in the Henry Hub natural gas price forecast annually. The 25-year nominal levelized price of natural gas is $4.36 per dekatherm and the 20-year nominal levelized price is $3.99 per dekatherm.

Figure 10.5: Henry Hub Natural Gas Price Forecast



Natural gas generation facilities in the west do not use Henry Hub as a fuel source but use supply basins where prices could be either higher or lower than the Henry Hub. Typical basins for the Northwest include Sumas for coastal plants on the northwest pipe system. Plants on the GTN pipeline could use prices from either AECO, Stanfield, or Malin depending on their contractual rights. Table 10.2 shows these basin differentials as a percent change from Henry Hub. In addition, this table includes basin nominal levelized prices for both 20 and 25 years for selected basins.

Table 10.2: Natural Gas Price Basin Differentials from Henry Hub

Year	Stanfield	Malin	Sumas	AECO	Rockies	Southern CA
2021	82.0%	85.5%	80.9%	57.6%	82.4%	89.8%
2025	86.9%	89.7%	86.5%	70.2%	87.7%	93.8%
2030	84.8%	87.4%	88.5%	74.9%	85.7%	91.7%
2035	92.7%	96.4%	89.6%	77.3%	92.7%	98.1%
2040	93.9%	97.3%	89.4%	76.9%	93.9%	98.8%
2045	93.8%	96.2%	90.7%	79.8%	94.2%	97.6%
25 yr	***$3.88***	***$4.02***	***$3.83***	***$3.20***	***$3.90***	***$4.14***
20 yr	***$3.51***	***$3.64***	***$3.49***	***$2.89***	***$3.53***	***$3.77***

As described earlier, natural gas prices are a significant predictor of electric prices. Due to this significance, the IRP analysis studies prices described on a stochastic basis for the 500 iterations. The methodology to change prices uses an autocorrelation algorithm to allow prices to experience price excursions, but not move randomly. The methodology works by focusing on the monthly change in prices. The forecast's month-to-month Expected Case change in prices is used as the mean of a lognormal distribution; then for the stochastic studies, a monthly natural gas price change in price is drawn from the distribution. The lognormal distribution shape and variability uses historical monthly volatility. Using the lognormal distribution allows for large upper price excursions seen in the historical dataset.

The average of the 500 stochastic prices are similar to the inputted expected price forecast described earlier in this chapter. Figure 10.6 illustrates the simulated data for the stochastic studies compared to the input data for the Stanfield price hub. The nominal levelized price for 20 years is $3.47 per dekatherm compared to the inputted price of $3.51 per dekatherm. These values may converge with a larger sample size. The median price is also lower at $3.35 per dekatherm. The lower price illustrates the skewness of the distribution to bias prices higher. Another component of the stochastic nature of the forecast is the growth in variability. In the first year, prices vary 13 percent around the mean, or the standard deviation as a percent of the mean. By 2040, this value is 32 percent and 35 percent by 2040. Avista uses higher variation in later years because the accuracy and knowledge of future natural gas prices is more uncertain.

Another way to visualize Avista's natural gas price assumption is in Figure 10.7. This charge shows the 20-year nominal levelized prices for Stanfield in a histogram view to demonstrate the skewness of the natural gas price forecast.

Figure 10.6: Stochastic Stanfield Natural Gas Price Forecast

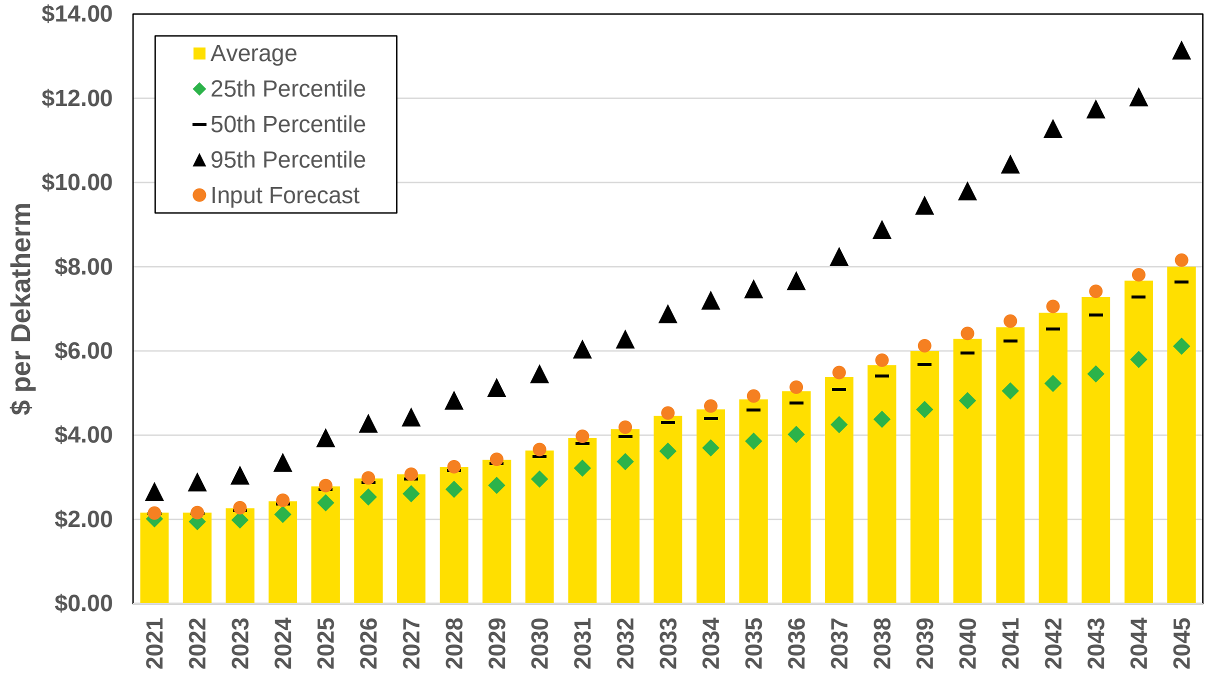
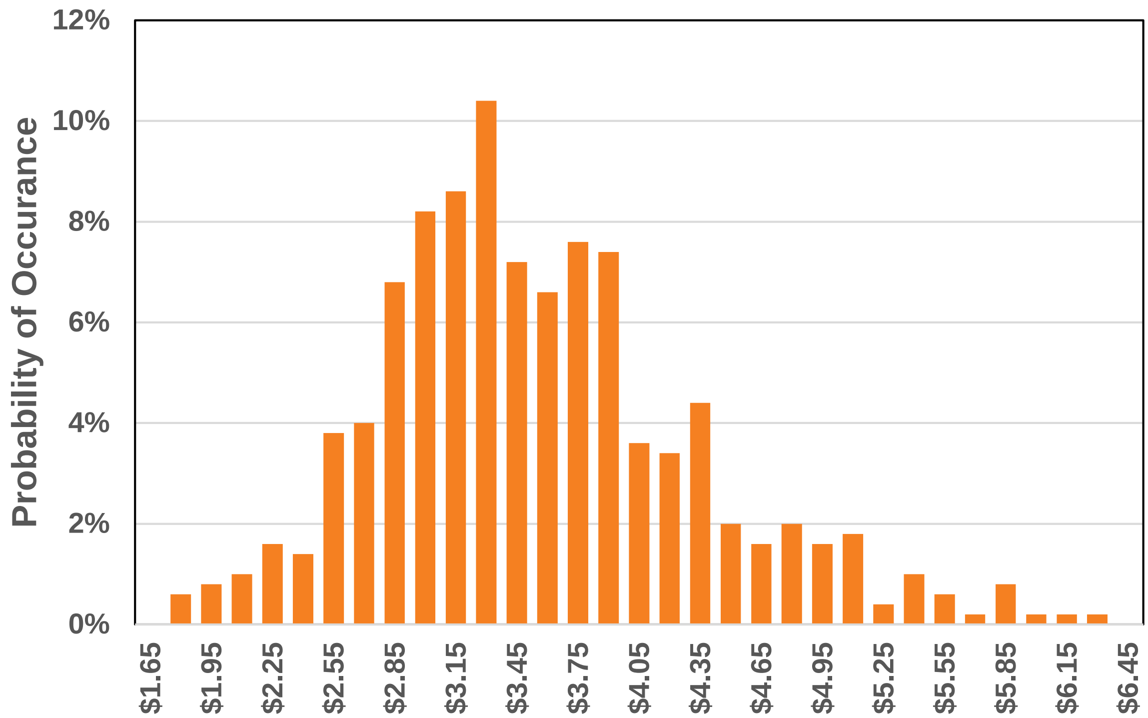


Figure 10.7: Stanfield Nominal 20-Year Nominal Levelized Price Distribution



Regional Coal Prices

Coal-fired generation facilities are still an important part of the resource mix across the Western Interconnect. In 2018, coal met 21 percent of Western Interconnect loads, although this amount was 36 percent in 2001. Coal pricing is typically different from natural gas pricing. Natural gas is a commodity delivered by pipeline, whereas coal delivery can be by rail or by conveyor. Typically, the coal contracts are longer term and supplier specific. Avista uses the Energy Exemplar coal forecast as they review FERC filings for each of the coal plants to determine historical pricing, and they use the EIA Annual Energy Outlook reports for future pricing.

Future coal pricing has price uncertainty like natural gas prices. Although its effect on market clearing pricing is less as coal-fired generation rarely sets on the margin in Avista's marketplace. Labor, steel cost, and transportation costs drive coal price uncertainty; transportation is the primary coal price driver. There is also uncertainty in fuel suppliers as the coal industry is restructuring. Given the small effect on market prices, Avista chose not to model this input stochastically.

Hydroelectric

The Northwest U.S., British Columbia, and California have substantial hydroelectric generation capacity. Hydroelectric resources served 57 percent of load in the Northwest. Although over the entire Western Interconnect, hydroelectric generation serves 24 percent of load. A favorable characteristic of hydroelectric power is its ability to provide near-instantaneous generation up to and potentially beyond its nameplate rating. Hydroelectric generation is valuable for meeting peak load, following general intra-day load trends, storing and shaping energy for sale during higher-valued hours, and integrating variable generation resources. The key drawback to hydroelectric generation is its variability and limited fuel supply.

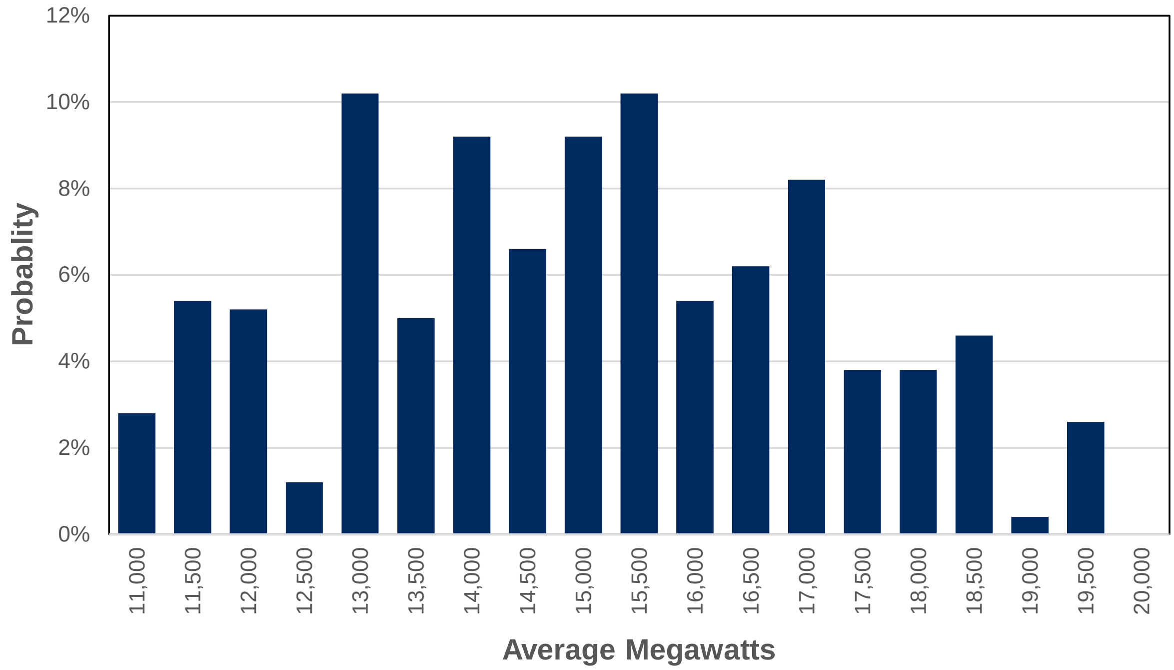
This IRP uses an 80-year hydroelectric data record. The study provides monthly energy levels for the region over an 80-year hydrological record spanning 1928 to 2009[6]. Many IRP studies use an average of the hydroelectric record, whereas stochastic studies randomly draw from the record, as the historical distribution of hydroelectric generation is not normally distributed. Avista uses both methodologies. Figure 10.8 shows the average hydroelectric energy as 14,750 aMW in the northwest for 2021, defined here as Washington, Oregon, Idaho and western Montana. The chart also shows the range in potential energy used in the stochastic study, with a 10th percentile water year of 11,564 aMW (-22 percent) and a 90th percentile water year of 17,600 aMW (+19 percent). The EIA reports detailed generation back to 2001. This was a historically low year with 11,098 aMW generated, but in 2018, 15,930 aMW was generated. Over the 18-year period, the average was 14,875 aMW and is right in line with the 80-year historical average. Although, generation from 2009 and 2018 averaged 15,411 aMW.

Aurora maps each hydroelectric plant to a load zone, creating a similar energy shape for all plants in the load zone. For Avista's hydroelectric plants, Aurora uses the output from its own proprietary software with a more accurate representation of operating

[6] The Bonneville Power Administration provides the underlying data use for regional hydroelectric data.

characteristics and capabilities. Aurora represents hydroelectric plants using annual and monthly capacity factors, minimum and maximum generation levels, and sustained peaking generation capabilities. The model's objective, subject to constraints, shifts hydroelectric generation into peak load hours to maximize the value of the system consistent with actual operations.

Figure 10.8: Northwest Expected Energy



Wind Variation and Pricing

Wind is a growing generation source to meet customer load. As of 2018, 7 percent of regional load was met by wind compared to nearly zero in 2001. Capturing the variation of wind generation on an hourly basis is important in fundamental power supply models due to the volatility and its effect on the other generation resources and the effect to electric market clearing prices. Energy Exemplar made significant progress populating a larger database of historical wind data points throughout North America. This IRP leverages their work but takes it one-step further by including a stochastic component to change the wind shape for each year. Avista uses the same methodology for developing its wind variation as discussed in previous IRPs. The technique includes an auto correlation algorithm with a focus on the change in generation hour-to-hour and also includes seasonal effects of the generation.

To simplify the amount of data Avista, developed 15 different annual hourly wind generation shapes that are randomly drawn for each year of the 25-year forecast. By capturing this volatility, the model can properly estimate hours with oversupply compared to using monthly average generation factors.

Solar

Like wind, solar is quickly increasing its market share in the Western Interconnect as a way to serve loads. Solar served 6 percent of the total requirement in 2018, but was just 2 percent in 2016 (both of these estimates exclude behind the meter solar generation). With Avista's acquisition of solar, along with its quick rise as a dominate energy supplier, better and more information is available to properly model the generation. In previous IRPs, limited solar shapes were available for each of the areas within the Aurora model, but now multiple shapes with multiple configurations are available. The model has data for fixed panels and single axis technology types along with multiple locations within an area. As solar continues to grow, additional details will be available and incorporated into future IRP modeling. One of these new techniques should include multiple hourly solar shapes similar to that used with wind, so that the model can account for solar variation due to cloud cover.

Other Generation Operating Characteristics

Avista uses the Energy Exemplar database assumptions for all other generation types, except for its owned and controlled resources. For Avista's resources, more detailed confidential information is used. The other major difference requiring a discussion for use of the Aurora software is the method of handling generation forced outages. Forced outage and mechanical failure is a common problem for all generation resources. Typically, the modeling for these events is de-rated generation. This means the available output is lowered to reflect the outages. Avista uses this method for solar, wind, hydroelectric, and small thermal plants; but uses a randomized outage technique for larger thermal plants where the model randomly causes an outage for a plant based on its historical outage rate and keep the plant offline for its historical mean time to repair.

Negative Pricing and Oversupply

Avista includes adjustments in the Aurora model to account for oversupply's effect on the Mid-Columbia market and the resulting negative price effect. Negative pricing occurs when there too much generation that wants to dispatch and not enough load to serve with it. This occurs most often in the Northwest when much of the hydro system is running in the spring months due to run off and wind projects are also generating and do not have the economic incentive to shut off due to their requirement to generate for PTC, REC, or PPA reasons. Hydro resources are dispatchable, but they may not be able to dispatch off due to total dissolved gas issues they may create if water is spilled instead of generated. This phenomenon will likely increase as more wind and solar generation is added to the system where there are PTC's in place or incentives to generate at zero pricing due to clean energy generation requirements. To model this effect in Aurora, Avista must change the economic dispatch prices for several resources that have dispatch drivers beyond fuel costs.

The first change Avista made is to change the hydro dispatch order. This means making hydro resources a "must run" resource or last resource to turn off. To do this, hydro generation is assigned a negative $30 per MWh price (2018 dollars)[7]. The next change is to assign an $8 per MWh (2018$) reduction in cost for renewable resources to reflect their preference for meeting state renewable portfolio standards (RPS). The last adjustment is to include a Production Tax Credit (PTC) for resources with this benefit. After these adjustments, the model will turn off resources when there is too much generation and the last resource turned off sets the marginal price.

There could be potential solutions to reducing the amounts of negative prices hours going forward. One method would reduce the incentive to generate when the power is not needed. Meaning, counting the "spilled" generation toward meeting the clean energy requirements or meeting the generation requirements for the PTC. Other solutions are to develop load-based options that can take advantage of wholesale market and increase their requirements. The third method is storage. As storage cost decreases and oversupply increases, storage resources may alleviate oversupply if storage becomes a large enough resource. For IRP purposes, Avista includes the negative pricing effects so that load or storage based options can see the pricing effects in the market for its economic analysis. Without these adjustments, expected generation from renewable resources may be over estimated by not including the hours of the year it will be curtailed.

Greenhouse Gas Pricing

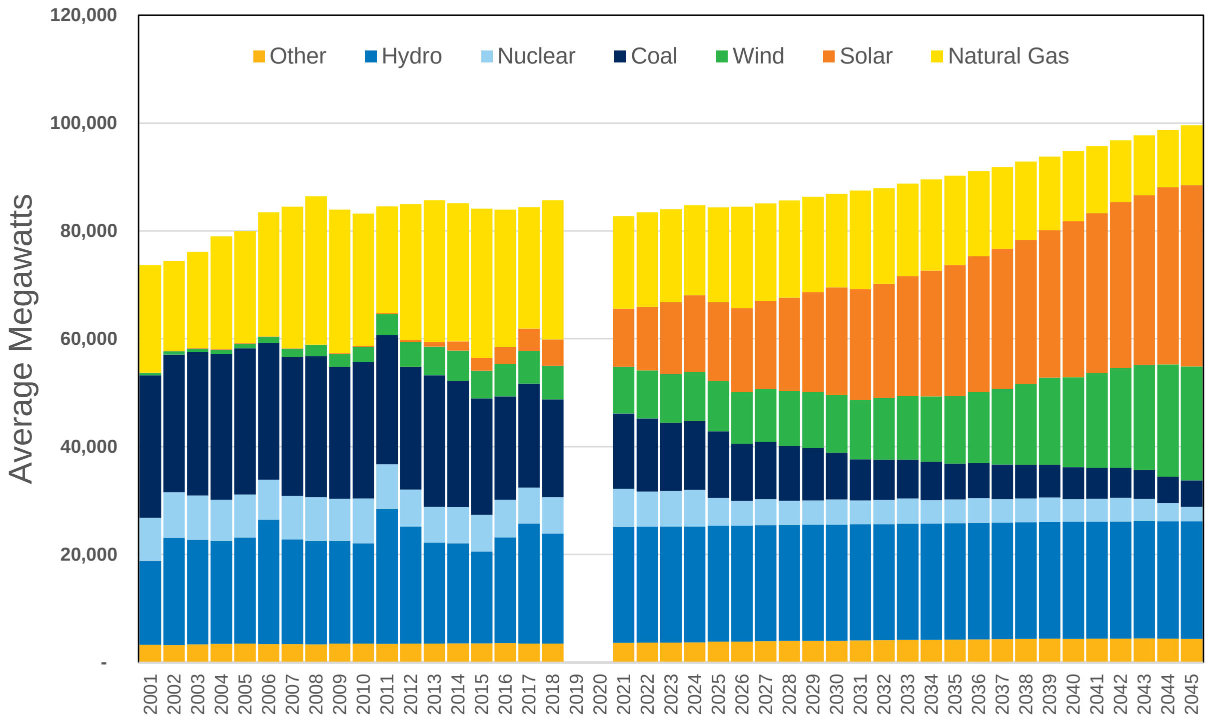
Many states and provinces enacted greenhouse gas emissions reduction programs. Other states are in discussion for such programs. Some states have trading mechanisms while others chose clean energy targets. From a modeling perspective, Aurora can model either, but different policy choice can result in dissimilar impacts to electric wholesale pricing. Clean energy target programs, such as Washington's, generally depress prices due to increasing amounts of low margin priced resources Programs like California's cap and trade push wholesale prices upwards. Avista includes known programs in California, British Columbia, and Alberta in its modeling as a carbon "tax." The carbon tax means the model includes a specified price on emissions. At the time of the development of this analysis, Oregon was close to enacting a cap and trade program. Avista proactively included this trading mechanism for modeling purposes even though Oregon ultimately failed to pass a cap and trade program in the 2019 legislative session. To account for these emissions, Avista modeled a cap on emissions of 3.6 million tons within Oregon. Although, this modeling cap was rarely enforced due to the influx of renewables from other environmental policies.

[7] These plants cannot be designated with a "must run" designation due to the must run resources would require resources to dispatch at minimum generation and for modeling purposes, hydro minimum generation is zero in the event of low flows.

Electric Resource and Emissions Forecast

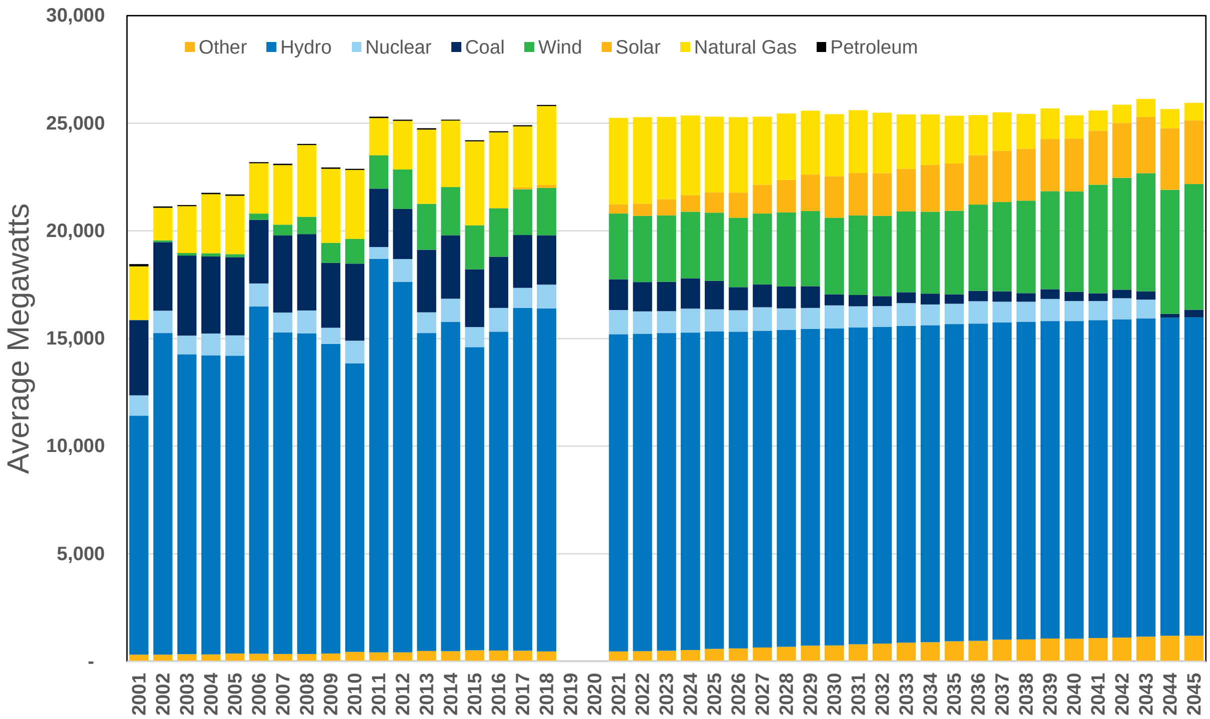
Avista forecasts a major shift to clean energy resources across the Western Interconnect in the next 25 years. Figure 10.9 shows the historical and forecast generation for the U.S. portion of the Western Interconnect. In 2018, 41 percent of load is served by clean energy, increasing to 65 percent by 2030, and 81 percent by 2045. To achieve this shift in energy, while also serving new loads, solar and wind production will need to increase at the expense of coal and natural gas. Although without development of significant new storage technologies, thermal resources are required to help meet system needs during peak weather events, especially in the Northwest winter.

Figure 10.9: Generation Technology History and Forecast



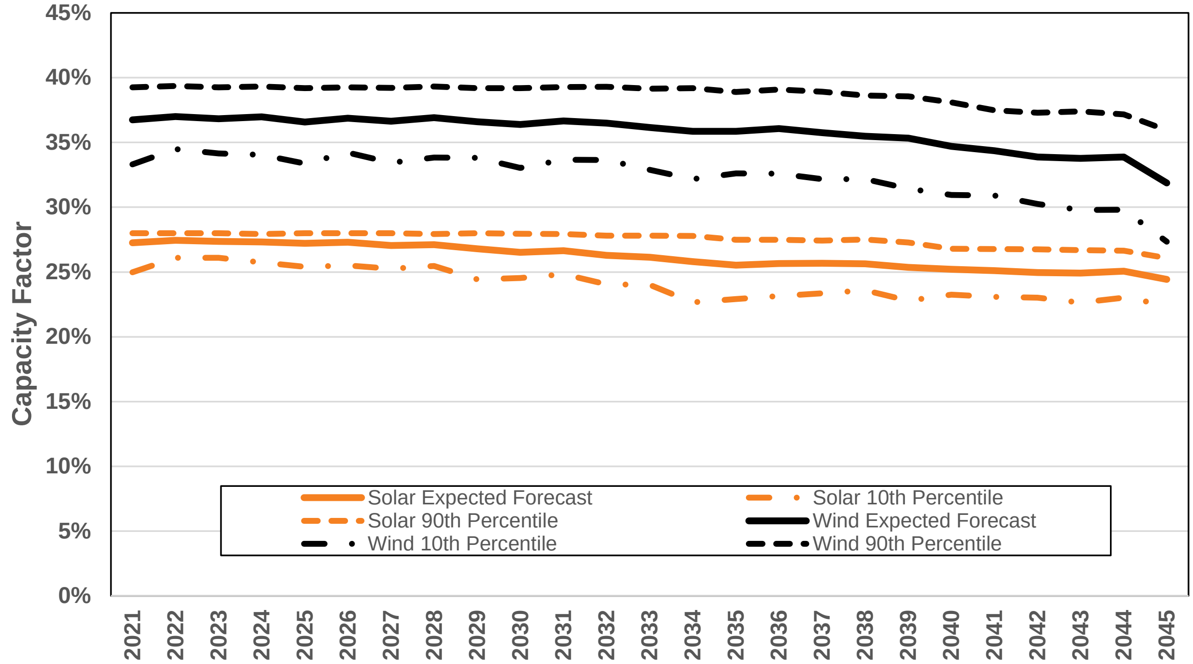
The northwest will also have significant changes in future generation. This forecast expects coal, natural gas, and nuclear generation to be limited by 2045; and the remaining generation requirements will be met with solar, wind, and hydro generation. As of 2018, 77 percent of the northwest generation was clean generation, but by 2030, the plan expects it to increase to 87 percent and 96 percent by 2045 as shown in Figure 10.10. Achieving these ambitious clean energy goals will require a doubling of wind generation and an 18 fold increase in solar energy from the 2018 generation levels. This results in solar providing 11 percent of future generation and wind 22 percent. Avista expects solar generation will be the renewable resource of choice in the northwest as quality wind sites are developed and costly transmission constraints will prohibit new wind in other locations due to solar's price competitiveness.

Figure 10.10: Northwest Generation Technology History and Forecast



Due to the large increases in renewable energy and limited long-term economic storage solution, this forecast expects renewable generation curtailments even with the pricing preferences included in the model. Figure 10.11 below shows how a Northwest solar and wind plant's dispatch will change on an annual average basis over the 500 simulations. By 2030, solar dispatches 3 percent less and wind 1 percent less; but by 2045 solar is 10 percent lower and wind 13 percent lower on average. Also shown on the chart is the 10th and 90th percentiles to illustrate how production could change under different conditions of the 500 simulations.

Figure 10.11: Wind and Solar Curtailment Forecast



Regional Greenhouse Gas Emissions

Greenhouse gas emissions are likely to significantly decrease with the retirement of coal generation facilities and solar/wind resources displacing additional natural gas generation. Avista estimates greenhouse gas emissions for plants within the U.S. Western Interconnect at approximately 230 million metric tons in 2017, which is very close to the 1990 emissions levels of 227 million metric tons. Avista obtained historical data back to 1980; the emissions minimum since 1980 was in 1983, at 154 million metric tons.

In our market modeling, Avista only tracks emission where the emissions are sourced and does not estimate how emissions will be assigned by each state for transfers, such as emissions generated in Utah for serving customers in California. Figure 10.15 shows the percent totals. The largest emitters are Arizona and Colorado, followed by California, Utah, and Wyoming. The four northwest states generate 14 percent of the total emissions.

Avista expects emissions to quickly fall by 20 percent by 2021 compared to 2017 due to coal plant retirements. By 2045, emissions fall by 62 percent compared to 1990 levels as shown in Figure 10.13. All states will have a reduction in emissions in this forecast. The greatest reductions by percentage are Washington (91 percent), Oregon (85 percent), and New Mexico (75 percent). The greatest reductions by tons are Colorado (23 MMT), Arizona (22 MMT), and Wyoming (18 MMT).

Figure 10.12: 2017 Greenhouse Gas Emissions

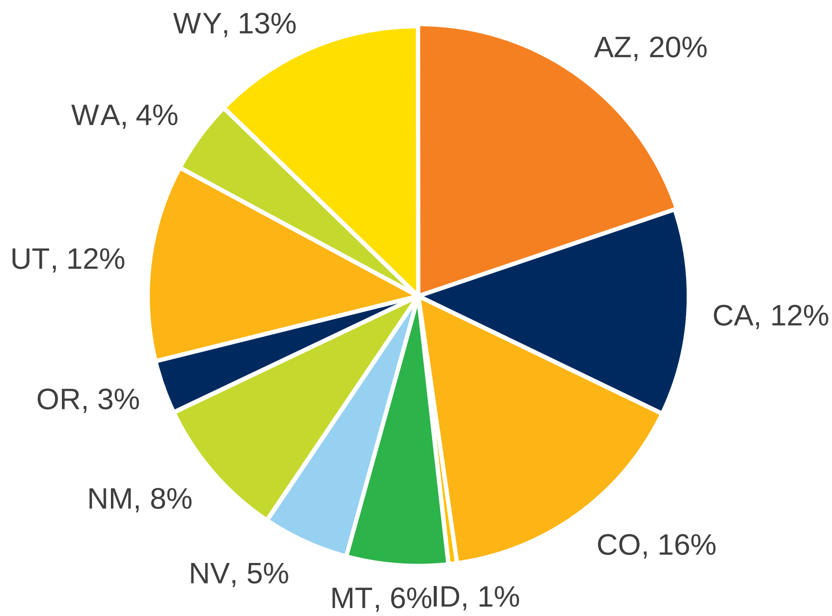
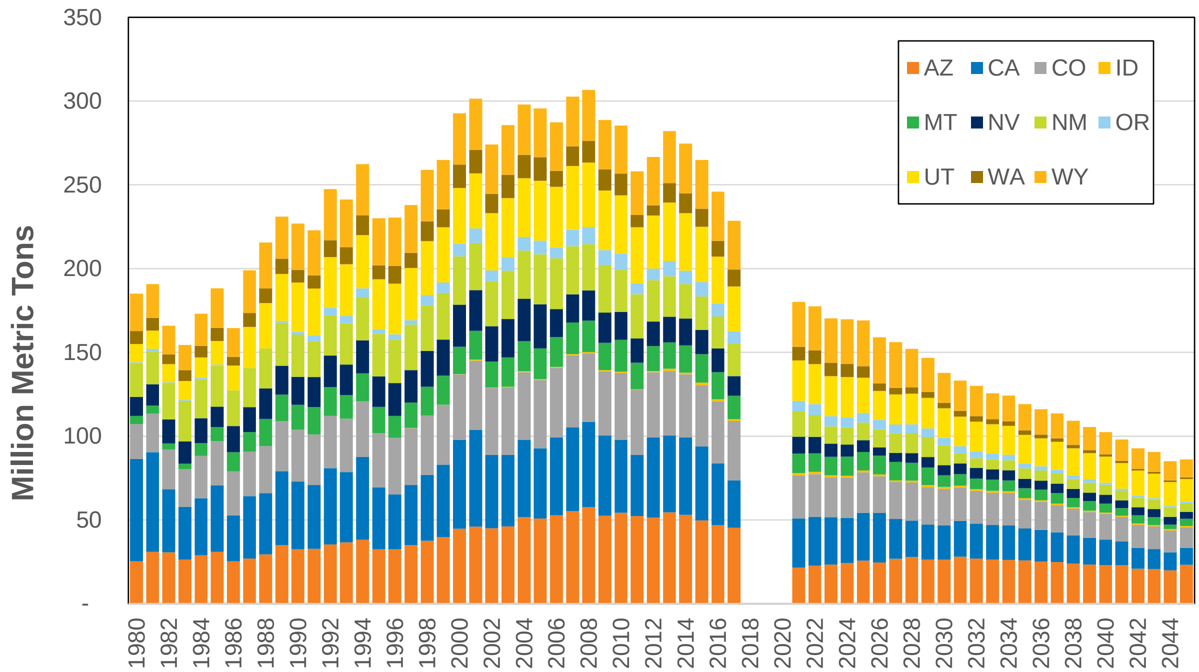


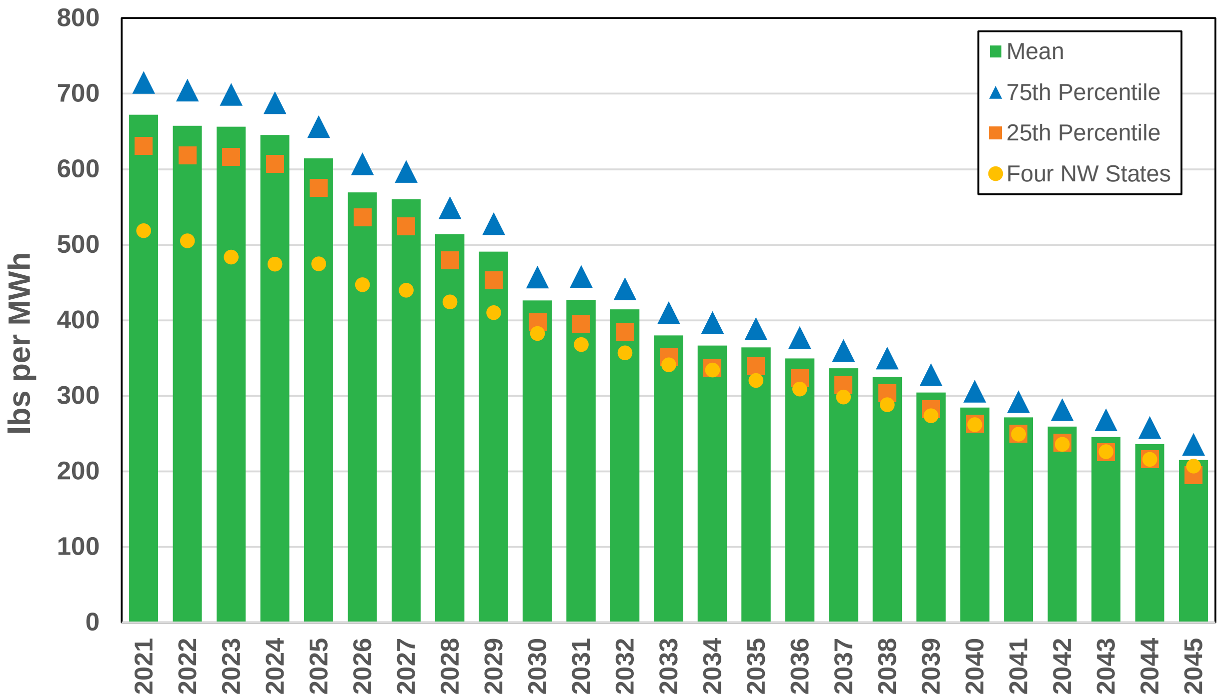
Figure 10.13: Greenhouse Gas Emissions Forecast



Regional Greenhouse Gas Emissions Intensity

To understand the emissions impacts of Avista's market purchases, Avista uses regional emissions intensity to estimate associated emissions from these short-term acquisitions. Avista uses the values shown in Figure 10.14 for each of the 500 simulations. The chart below shows the mean, 25th percentile, and 75th percentile. The emissions are included from Washington, Oregon, Idaho, Montana, Utah, and Wyoming. Emissions intensity will fall as additional renewables are added and coal plants retire, but the intensity rate will depend on the variation in hydro production. The locations for Avista potential market purchase radius is consistent with Washington's energy and emissions intensity report but is higher than Avista's likely counter parties for market purchases. To address this inconsistency, the four northwest states are shown in the yellow dots with lower emission intensity rates, although over time, the two values converge.

Figure 10.14: Northwest Regional Greenhouse Gas Emissions Intensity



Electric Market Price Forecast

This chapter describes the major inputs and assumptions the Aurora model uses to generate its electric price forecast. It also includes results for how resources will dispatch and how emissions change in the future with changes to state environmental policies. The next section describes the pricing effects to the Mid-Columbia wholesale market. These prices are an important part of the IRP as they determine the economic value of each resource for a comparison analysis against other demand and supply side resources.

Mid-Columbia Price Forecast

Two Expected Case forecasts are studied for the IRP. The first is the deterministic case which has variation in assumptions and the second study is the stochastic case where inputs vary. Each study uses hourly time steps between 2021 and 2045 for a simulation of over 219,000 hours. This process is time consuming when conducted 500 times. Running the Expected Case 500 times took over two weeks of continuous processing to complete. Time constraints limit the number of market scenarios.

The annual prices from both studies are shown in Figure 10.14 for flat pricing, meaning the average of all hourly prices over the year. This chart shows the annual distribution of the prices using the 10^{th} and 95^{th} percentiles compared to the mean, median, and deterministic prices. The pricing distribution is lognormal as prices continue to track natural gas pricing. The 25-year nominal levelized price of the deterministic study is $26.10 per MWh and $27.86 per MWh for the stochastic study, see Tables 10.3 and 10.4. Table 10.4 also includes a new price labeled as super peak evening. This price represents weekday prices between the hours of 4 pm and 10 pm. These prices represent hours where solar output is falling and prices will rise to encourage dispatch of other resources.

Figure 10.15: Mid-Columbia Electric Price Forecast Range

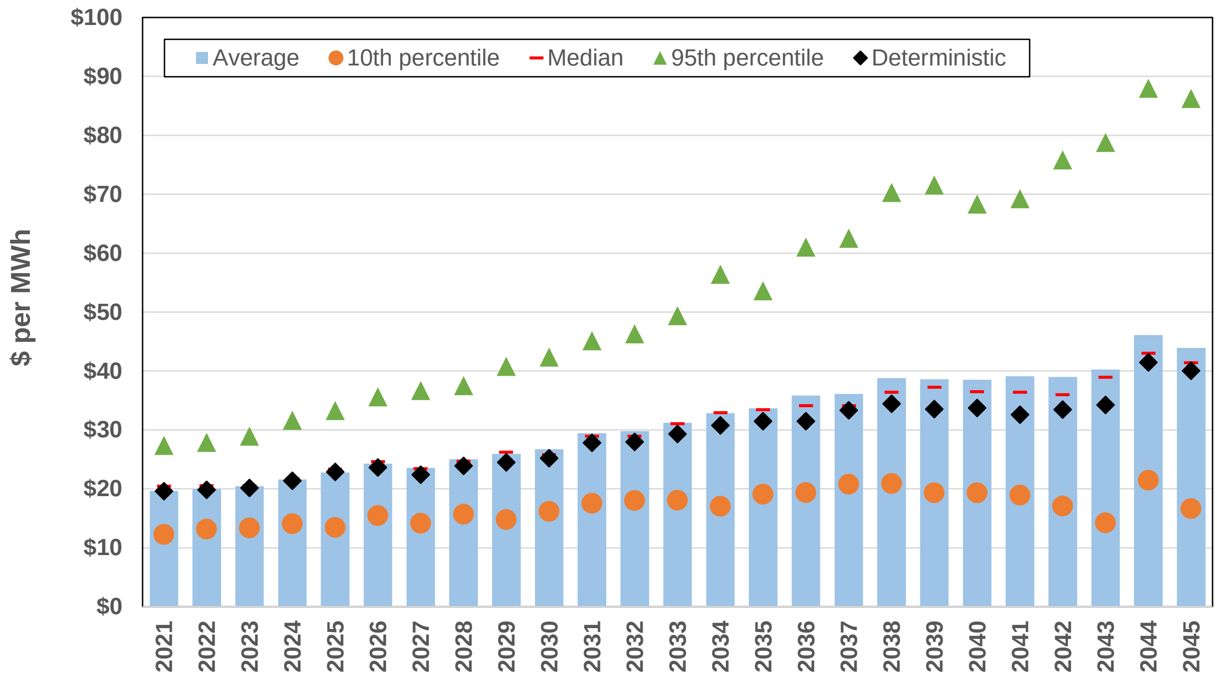


Table 10.3: Nominal Levelized Flat Mid-Columbia Electric Price Forecast

Metric	2021-2040 Levelized ($/MWh)	2021-2045 Levelized ($/MWh)
Deterministic	$25.06	$26.10
Stochastic Mean	$26.44	$27.86
10th Percentile	$20.63	$21.69
50th Percentile	$25.82	$27.12
95th Percentile	$35.87	$37.93

Table 10.4: Annual Average Mid-Columbia Electric Prices ($/MWh)

Year	Flat	Off-Peak	On-Peak	Super Peak Evening
2021	$19.67	$15.71	$22.64	$27.95
2022	$19.98	$16.28	$22.75	$28.61
2023	$20.44	$16.98	$23.05	$29.76
2024	$21.61	$18.28	$24.09	$31.54
2025	$22.76	$19.50	$25.19	$32.48
2026	$24.27	$21.43	$26.40	$34.67
2027	$23.57	$21.30	$25.27	$34.01
2028	$25.02	$23.35	$26.26	$36.73
2029	$25.92	$24.73	$26.80	$38.73
2030	$26.72	$26.25	$27.08	$41.52
2031	$29.46	$29.21	$29.66	$45.70
2032	$29.78	$29.54	$29.95	$47.17
2033	$31.22	$31.89	$30.74	$50.80
2034	$32.83	$34.06	$31.94	$54.50
2035	$33.66	$35.05	$32.64	$56.25
2036	$35.82	$37.16	$34.82	$60.63
2037	$36.12	$38.19	$34.58	$61.43
2038	$38.81	$40.76	$37.40	$66.43
2039	$38.60	$40.57	$37.13	$66.85
2040	$38.52	$40.84	$36.80	$69.79
2041	$39.09	$40.92	$37.74	$72.22
2042	$38.98	$40.31	$37.99	$73.58
2043	$40.24	$41.21	$39.51	$77.25
2044	$46.10	$47.15	$45.29	$86.30
2045	$43.94	$45.05	$43.11	$84.74
Levelized 2021-2040	**$26.44**	**$24.98**	**$27.55**	**$40.97**
Levelized 2021-2045	**$27.86**	**$26.66**	**$28.77**	**$44.50**

Traditionally on-peak prices are higher than off-peak prices. On-peak prices are typically 7 a.m. to 10 p.m. on weekdays plus Saturdays. This forecast shows off-peak prices outpacing on-peak prices on an annual basis beginning in 2033. This is due to the increased quantities of solar generation placed on the system depressing on-peak prices. The first monthly flip between on- and off-peak begins in March 2026, and as more solar is added to the system, spreads to other shoulder months until it appears in all months, except for the winter season where solar production is lowest.

Depending on the future level of storage and its duration, price shapes could flatten out rather then invert the day-time spread. Mid-day pricing will be low in all months going forward, driving on-peak prices lower. Although super peak evening prices after 4 p.m., when other resources will need to dispatch to serve load, these prices can be high if startup costs effect market pricing as expected in this forecast.

Figures 10.15 through 10.18 show the average prices for each hour of the season every 5 years of the price forecast. The spring and summer prices generally stay flat throughout the 25 years as these periods have large quantities of hydro and solar generation to stabilize prices, but mid-day prices decrease over time and the other time periods increase. The winter and autumn prices will have large price increases due to less available solar energy to shift unless enough long-term storage is available. With this analysis, current on/off-peak pricing will need to change into different products such as a morning peak, afternoon peak, mid-day, and night. Pricing for holidays and weekends likely will be less impactful on pricing except for the morning and evening peaks. Pricing for all resources will need to reflect these pricing curves so they can be properly valued against other resources.

Figure 10.16: Winter Average Hourly Electric Prices (December - February)

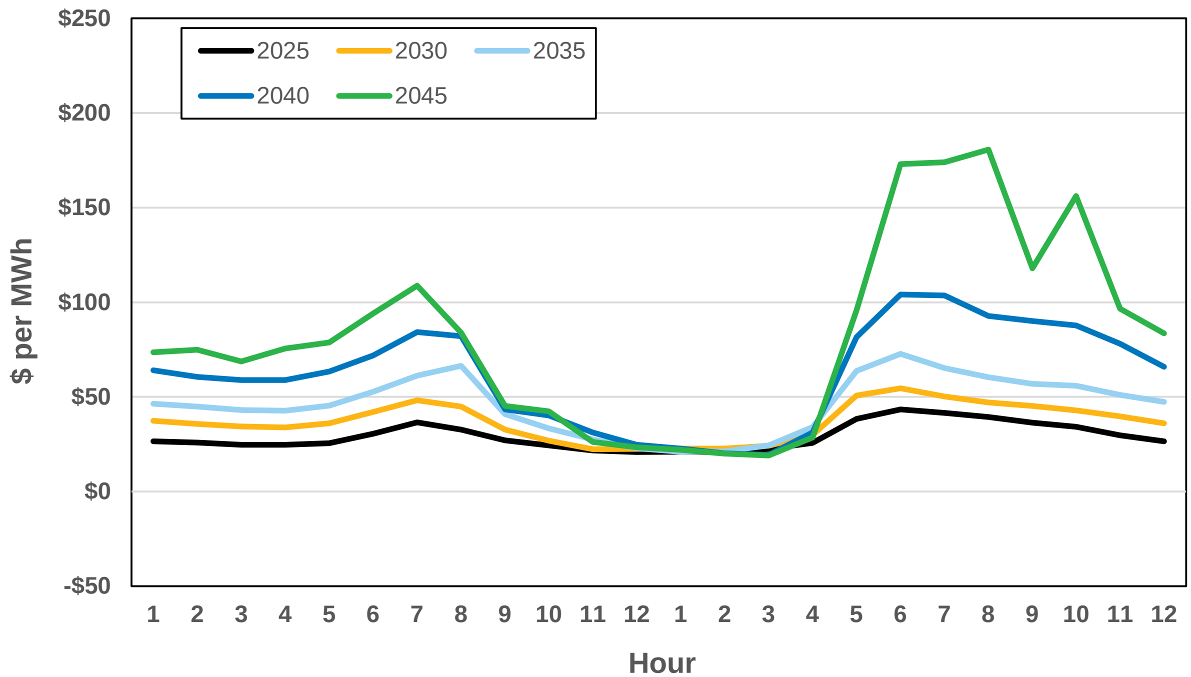


Figure 10.17: Spring Average Hourly Electric Prices (March - June)

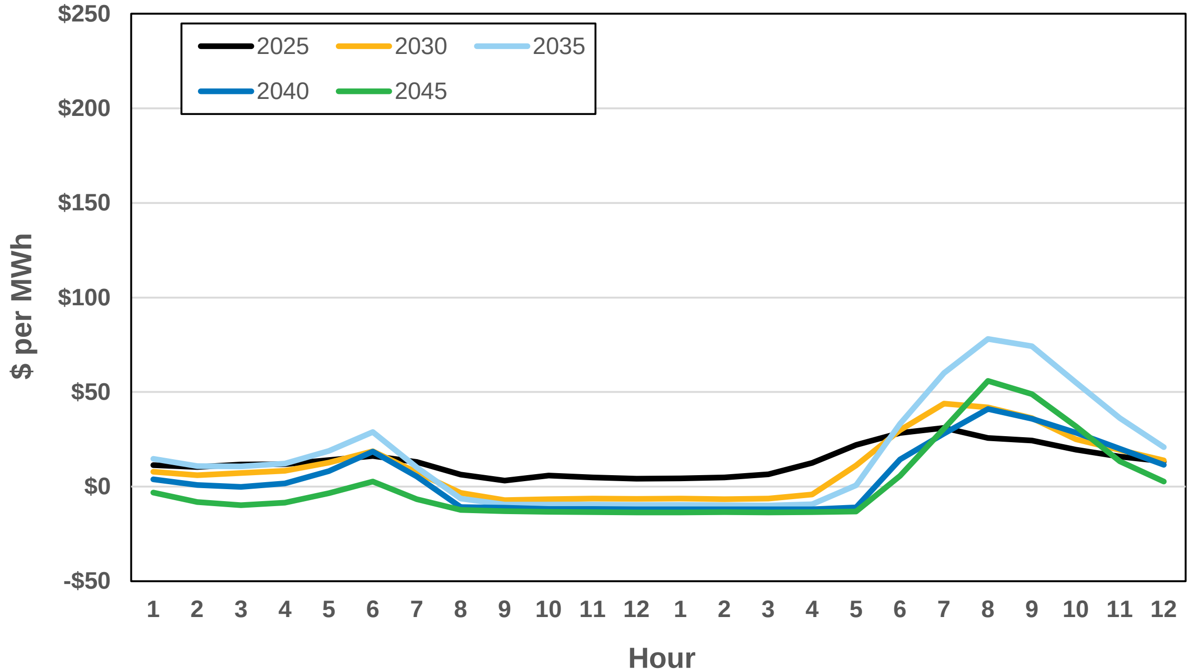


Figure 10.18: Summer Average Hourly Electric Prices (July - September)

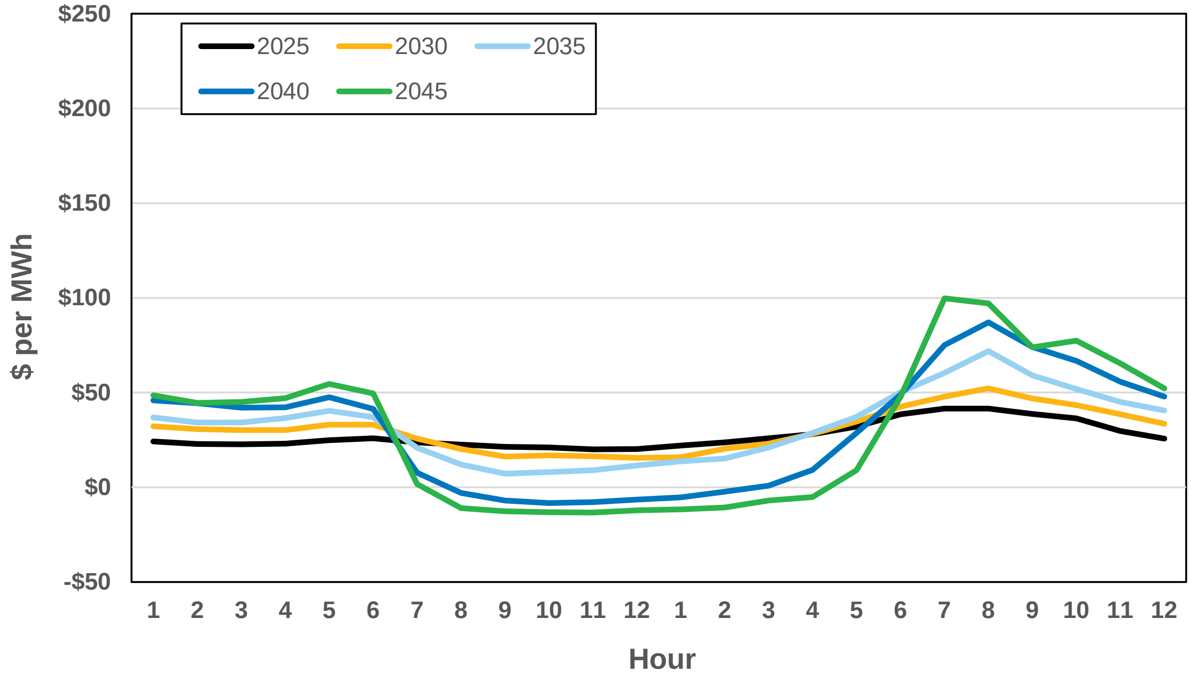
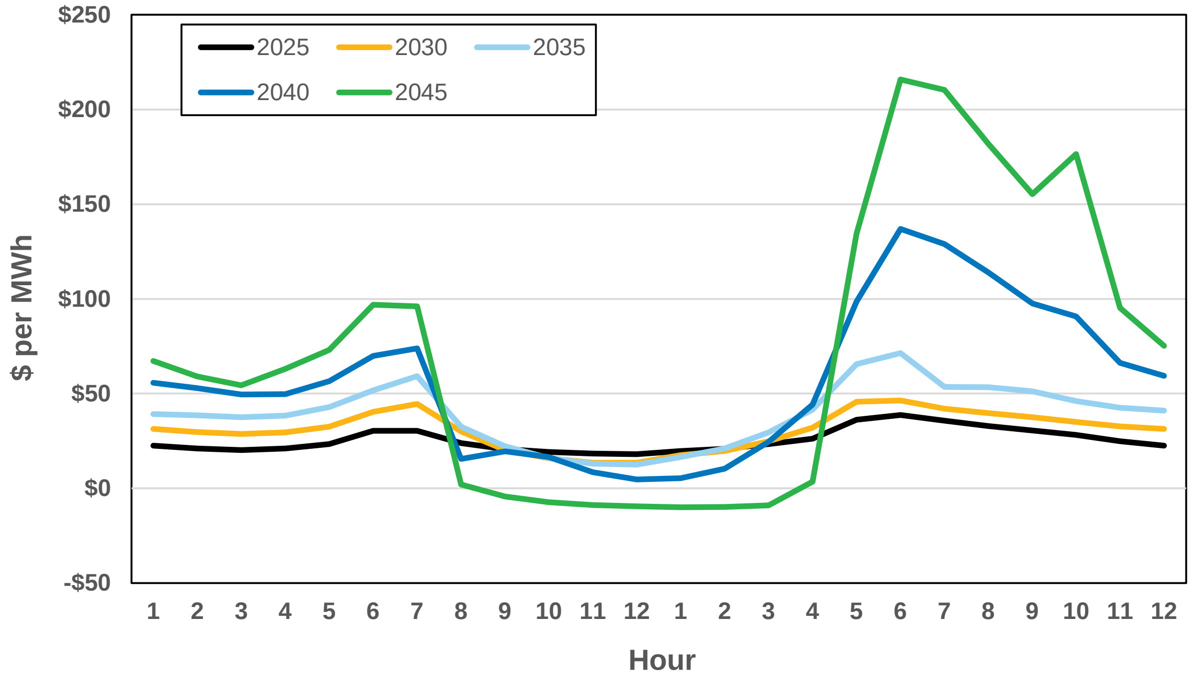


Figure 10.19: Autumn Average Hourly Electric Prices (October - November)



Scenario Analysis

Electric market prices will have an impact on this resource plan due to how each resource option performs compared to other resources. This comparison uses market prices along with how each resource performs when customers need them (i.e. winter sustained peak). As discussed earlier, market price forecasts can be computer processor and time sensitive. However, understanding specific effects on the market place are important to understand the risks involved with resource choice. Avista studied four additional scenarios beyond the 500 simulations of the Expected Case. Avista modeled each scenario deterministically. Deterministic studies are sufficient because the objective of the scenario is to understand the effect of the underlying change in assumption on the plan. The following market scenarios were conducted:

- **No Clean Energy Transformation Act (CETA) Scenario**: This study identifies how the market place would differ absent the law passed in Washington State in 2019. This study assists calculating financial impacts of the change in energy policy. The major change in this scenario removes the social cost of carbon from resource choices for Washington State customers and removes the requirement of clean resources beyond those in the Energy Independence Act.

- **Social Cost of Carbon Scenario**: This scenario shows the implications of national carbon policy using the social cost of carbon as a “tax” on the entire electric system. In this scenario, power plants use this cost for dispatch decisions. This scenario include a price of nearly $80 per metric ton in 2021 escalating to approximately $100 in 2030, $155 in 2040, and $182 in 2045. No changes to load were included from any price elasticity effects of higher electric prices.

- **Low Natural Gas Price Scenario**: Prevailing low natural gas prices will have an impact on the resource selection because it will keep electric prices low. This scenario assumes prices in 2021 will be the same price in all future years, or in other words, no change in inflation. The results of this scenario demonstrate effects to both coal-fired facilities and the economics of renewable resources in a low natural gas price environment.

- **High Natural Gas Price Scenario:** As opposed to the low natural gas price scenario, this scenario increases prices compared to the Expected Case using the 95th percentile of stochastic study. This equates to 23 percent higher prices in 2021, 50 percent higher prices in 2030, and 64 percent higher prices in 2045. This scenario should illustrate the price protection from non-natural gas-fired generation sources.

Scenario Electric Price Results

Wholesale electric prices increase in all but the low natural gas price scenario. Figure 10.19 shows the nominal levelized prices for each scenario on a 20-year and 25-year basis compared to the Expected Case's deterministic study. The "No CETA" scenario has a modest 5 percent increase in prices due to less renewable generation in the system. Including Social Cost of Carbon in the dispatch of wholesale generation increases prices by 75 percent. The Low Natural Gas Price scenario decreases the electric price forecast 30 percent. The Higher Natural Gas Price scenario increases electric prices by 39 percent. Figure 10.20 shows how the market prices materialize each year under the four scenarios. All the scenarios, except the Social Cost of Carbon scenario, have linear price forecasts. In the Social Cost of Carbon scenario, prices begin to fall because thermal generation costs rise until renewables dominate the market. In the High Natural Gas Price scenario, the end of the study bump in prices is due to increases in natural gas requirements due to the Columbia Generating Station assumed closure.

Figure 10.20: Mid-Columbia Nominal Levelized Prices Scenario Analysis

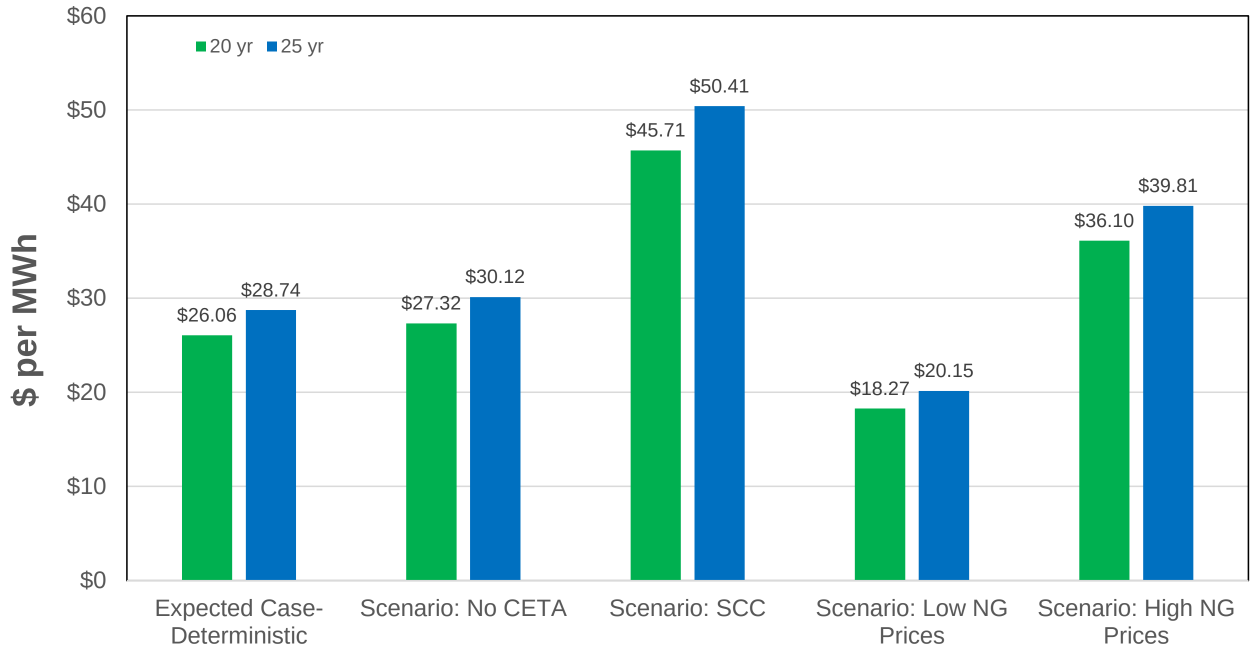
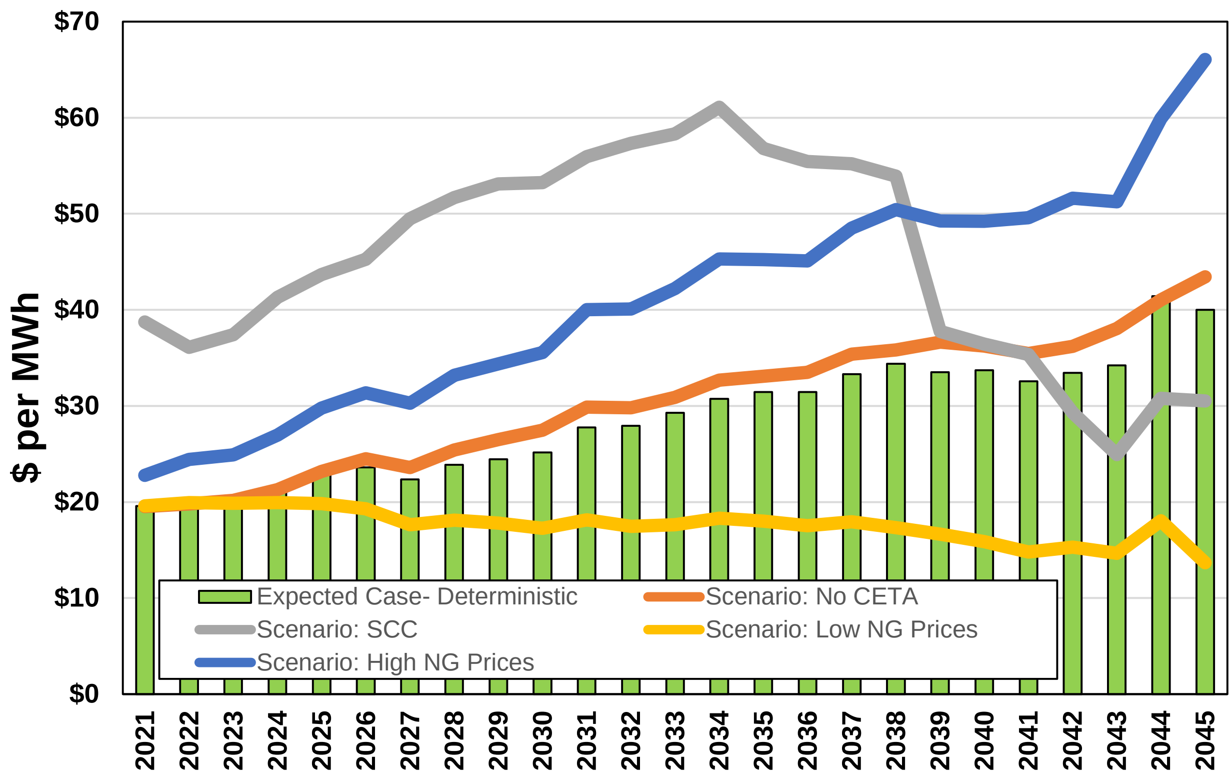


Figure 10.21: Mid-Columbia Annual Electric Price Scenario Analysis



Scenario Generation Dispatch Results

Each scenario has an effect on the type of generation constructed and dispatched in the Western Interconnect. Figure 10.21 highlights generation dispatch in each scenario for 2040 and Table 10.5 shows the percent change in dispatch compared to the expected case. The biggest changes in dispatch for the Social Cost of Carbon scenario where the "tax" on coal and natural gas decreases their dispatch and increases wind generation. The natural gas price scenarios also operate as expected where high prices increase coal generation and low prices decrease coal generation.

Figure 10.22: 2040 Western Interconnect Generation Forecast

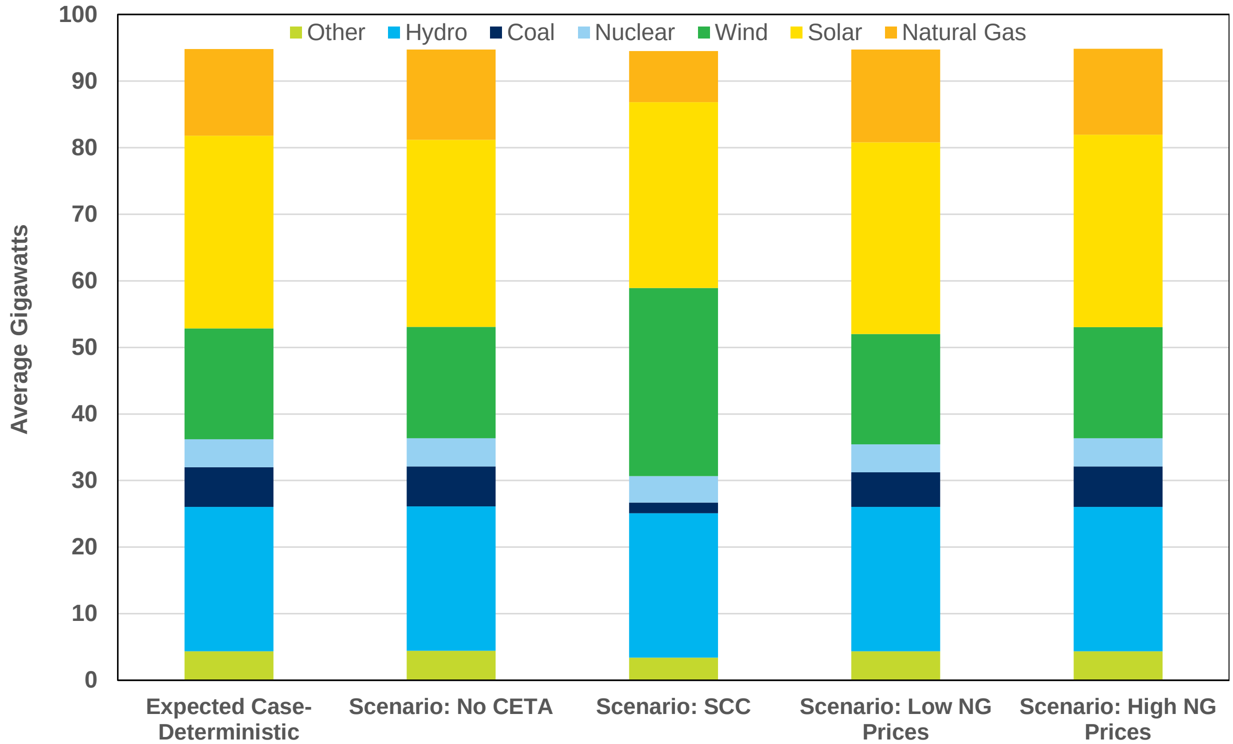
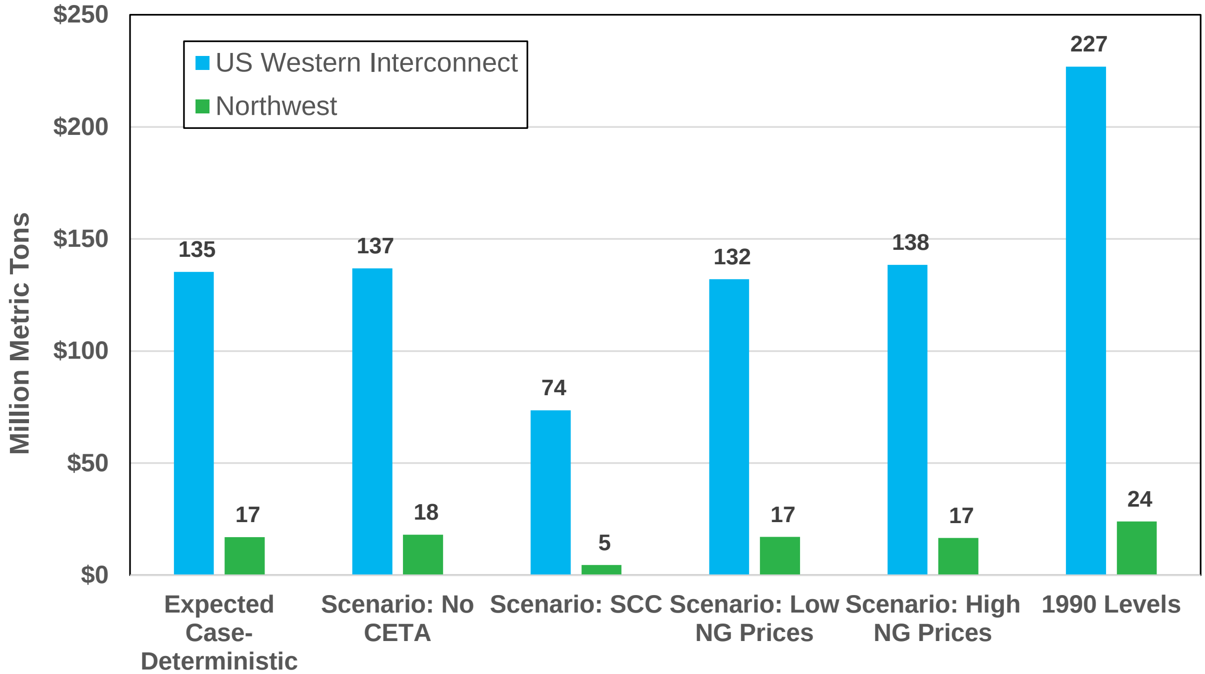


Table 10.5: Change in 2040 Regional Generation (Percent)

Scenario	Coal	Natural Gas	Hydro	Nuclear	Wind	Solar	Other
Scenario: No CETA	1	4	0	1	0	-3	2
Scenario: SCC	-73	-41	0	-6	70	-3	-22
Scenario: Low NG Prices	-13	7	0	-1	0	0	0
Scenario: High NG Prices	3	-1	0	0	0	0	0

The other major reason for the scenarios is to understand the impact of these futures to greenhouse gas emissions. Figure 10.22 shows scenario results on a levelized basis of emissions. This analysis assumes a 2.5 percent discount rate on the emissions to simplify the comparison of the quantity of emissions between the scenarios and the Expected Case. These analyses illustrates with the CETA policy reduces greenhouse gas emissions across the west by approximately two million metric tons per year, but only one million metric tons in the Northwest. Natural gas pricing has little effect on emissions in the northwest but affects other states more. The limitation in the northwest is due to low natural gas usage in these states. The Social Cost of Carbon has the greatest impact by drastically reducing emissions across all areas. In all scenarios, the emissions levels are lower than historical 1990 emissions levels.

Figure 10.23: 2021-2045 Levelized Greenhouse Gas Emissions



11. Preferred Resource Strategy

In April 2019, Avista announced a corporate goal to provide 100 percent “carbon neutral” energy by 2027 and by 2045 provide 100 percent clean energy, similar to the Washington requirements under the Clean Energy Transformation Act (CETA) for 2030 and 2045 respectively. Avista must maintain system reliability at affordable rates when achieving this goal. This will require renewable resources to remain cost competitive and for new technologies to emerge. This chapter outlines how Avista plans to meet its future resource needs including new CETA requirements and how we may achieve our own clean energy goals, while keeping costs within acceptable levels as determined by the Idaho and Washington utility commissions. Avista plans to acquire new resources by request for proposals (RFPs) and opportunistic resource acquisitions to deliver reliable power supply options to our customers at the lowest reasonable cost.

Section Highlights

- Avista will seek 300 MW of wind energy to be online in 2022, or later, from both the Northwest and Montana.
- A combination of Montana wind and storage resources meet the 2026 capacity deficits associated with the shutdown of Colstrip and the expiration of the Lancaster contract.
- Wind resources are preferred over solar due to the potential to generate during periods of time when solar resources are not contributing to the grid, and the desire to avoid resources whose timing is highly correlated with solar surplus across the Western Interconnection.
- Avista must plan to meet future capacity needs in a flexible manner depending on what resources materialize from RFPs.
- Energy efficiency will meet 71.4 percent of customer’s new energy requirements.
- Demand response programs will begin in 2025 ramping up to meet 100 MW of peak demand by 2035.

The IRP attempts to project the resource acquisition strategy using the best information available at the time and our understanding of the potential requirements of Washington State’s CETA. At the time of the drafting of this IRP, Washington had not released rules regarding how power will be accounted for when meeting the 100 percent clean goal and how the alternative compliance will work. Further, Avista did not include alternative compliance options to meet CETA goals. Avista expects the next IRP (2021) will address these rules when they are available. Avista’s Preferred Resource Strategy (PRS) describes the lowest reasonable cost portfolio of resources given Avista’s need for new capacity and clean energy resources, while taking into account social and economic factors prescribed by state policies of where Avista serves customers. This analysis also considers energy market risks, as alternative portfolios. The analysis tests sensitivities against the preferred portfolio to measure its cost changes to critical external factors like higher or lower than expected levels of load growth.

The resource strategy includes both supply side resources and load management options for customers including energy efficiency and demand response. The IRP measures resource options against each other to find the lowest cost portfolio of resources to meet resource deficits for winter and summer capacity, energy, and clean energy requirements. Avista also explored ways to integrate distribution and transmission resource needs to co-optimize all available options to serve its customers.

Resource Selection Process

Avista uses three models to evaluate resources for inclusion in the PRS. First is the Aurora model, discussed in Chapter 10, which Avista uses to develop the electric price forecast. The second model is Avista's Reliability Assessment Model (ARAM), to test the current resource portfolio's reliability metrics and each resource option's contribution to overall portfolio reliability. Chapter 6 and Chapter 9 discuss these topics. The third model, PRiSM (Preferred Resource Strategy Model), aids resource selection given the information determined from the market price forecast and each resource's reliability characteristics. PRiSM evaluates each resource option's costs (capital and operating), capabilities, and operating margins compared to each other to determine the lowest cost portfolio of resources to meet Avista resource needs (from Chapter 6). The model also considers risk as evaluated by 500 different potential market futures.

PRiSM

Avista staff developed the first version of PRiSM in 2002 to support resource decision making in the 2003 IRP. Ongoing enhancements improved the model since its initial development. PRiSM uses a mixed integer programming routine to support complex decision making with multiple objectives. These tools provide optimal values for variables, given system constraints. The model uses an add-in function to Excel from Lindo Systems named What's Best and the Gurobi solver. This software is the user interface to determine which model inputs are variables and allows for the creation of constraints on the system. For example, Avista must simultaneously meet its clean energy standard in Washington and its projected winter capacity shortfall.

The model solves using the net present value of resource costs given the following inputs:

1. Expected future deficiencies
    - Summer Planning Margin from ARAM
    - Winter Planning Margin from ARAM
    - Annual energy
    - Clean energy requirements
2. Costs to serve future retail loads as if served by the wholesale marketplace (from Aurora)
3. Existing resource and energy efficiency contributions
    - Operating margins

    - Fixed operating costs
4. Supply-side resource, energy efficiency, and demand response options
    - Fixed operating costs
    - Return on capital
    - Interest expense
    - Taxes
    - Power Purchase Agreements
    - Peak Contribution from ARAM
    - Generation levels
    - Emission levels
5. Constraints
    - Must meet energy, capacity and clean energy shortfalls without market reliance
    - Resource quantities available to meet future deficits

The Preferred Resource Strategy

To meet future customer load, Avista uses a combined strategy of acquiring energy efficiency (reducing its customer's energy consumption), working with customers to use energy differently through demand response programs, upgrading our existing thermal and hydroelectric generation fleet, contracting for new renewable energy resources, and acquiring storage resources. Avista may take advantage of new opportunities, but will seek the lowest cost and environmentally sustainable energy resources for our customers. In addition, Avista may acquire resources other than those identified as preferred due to actual pricing, lack of availability, the reliability benefits not materializing, or the inability to meet state laws.

Avista's resource strategy relies on available information at the time of this analysis and is subject to change based on how Avista expects customers to use energy in the future, how projected resource costs change, and on how market price conditions influence the analysis and future acquisition. The strategy uses Avista's interpretation of the new Washington State CETA requirements. At the time of this IRP, rules are in development and Avista's portfolio may change depending upon the methodology the Washington Commission uses to account for clean resources and alternative compliance.

Resource selections use economics, environmental objectives, and maintaining customers reliably for decisions. Avista's first resource adequacy shortfall occurs in January 2026, when Avista assumes Colstrip will not be available for purposes of this IRP and is no longer available to serve Washington customers due to Washington state law excluding the plant from customer rates. Although, it would be beneficial for Colstrip to remain in operation through the 2025-2026 heating season for reliability unless new capacity is under Avista's control. Avista's analysis of Colstrip in this IRP (Chapter 12) indicates retiring the plant for Idaho customers in 2025 rather than 2035 is the economic choice[1]. Avista cannot unilaterally close Colstrip units 3 and 4 under the ownership agreement. Avista's energy needs increase later in 2026 when Avista's contract with

[1] Avista did not model any alternative shut down dates in this plan.

Lancaster[2] ends in October 2026. Filling these resource losses drives Avista's need for additional capacity. Avista may have needs for additional renewable energy to meet Washington State's CETA. New renewable resource acquisitions will likely begin as early as 2022 to help with the transition to a cleaner resource portfolio. Avista may also acquire resources or contracts to minimize customer's power costs.

Avista's resource plan is larger than in previous IRPs due to expected resource retirements and new renewable energy requirements driven by the assumption Avista does not use Idaho's share of the hydroelectric system to comply with CETA's clean goals (except for the 20 percent alternative compliance). Avista's interpretation of the law allows this energy to transfer between states with compensation to Idaho customers but awaits rulemaking before adjusting its resource plan.

The PRS divides the resource strategy between the first decade (2021-2030), second decade (2031-2040), and after 2040. Additional energy efficiency additions will occur over the 25-year plan. The next several sections of this chapter detail the expected resource acquisitions and summarize demand response and energy efficiency selections.

2021-2030 Supply Side Resource Selection

Avista will acquire new energy and capacity resources to meet clean energy goals and capacity deficits in the next several years. Table 11.1 shows a complete list of new generation selections. Avista's first selection is 200 MW of wind energy divided between Montana and the Northwest. Avista prioritized wind over other renewables due to its energy delivery profile combined with PPA price forecasts. Actual acquisition quantities and locations will be determined as part of RFPs and the transmission availability at the time of the acquisition.

Under the IRP resource assumptions, the PRS includes wind due to generation in higher-priced hours compared to solar and the potential for Montana wind projects to provide peak capacity toward meeting customers' winter peak load. In 2023, another 100 MW of wind will help meet future clean energy targets. In total, Avista estimates 122 aMW of clean energy procurement before 2023 to stay on track to meet the 80 percent CETA goal by 2030. Avista may release an RFP in the second quarter of 2020 to solicit projects to meet these goals. This RFP would be open to any clean resource with deliveries beginning in 2022. While the IRP identifies online dates between 2022 and 2023, other terms will receive consideration as long as the terms are in the best interests of Avista's customers and the resources meet the objectives of the CETA and Avista's clean energy goals.

[2] Rathdrum Power, LLC, Combined Cycle Combustion Turbine.

Table 11.1: 2020 Preferred Resource Strategy (2021-2030)

Resource	Time Period	ISO Conditions (MW)	Equivalent Winter Peak Capacity (MW)	Energy Capability (aMW)
On-system wind	2022	100	5	37
Montana wind	2022	100	40	48
On-system wind	2023	100	5	37
Kettle Falls modernization	2024	12	12	10
Rathdrum CT upgrade	2026	24	24	22
Long duration pumped hydro storage	2026	175	175	n/a
Post Falls modernization	2026	8	3.7	4.5
Montana wind	2027	200	80	96
Total		**719**	**344.7**	**254.5**

Avista, like the other Washington utilities with an ownership share in Colstrip Units 3 and 4, is required to cease recovering the cost of coal-fired generation in Washington rates after 2025. While the fate of the plant will depend on a decision made by all owners of the facility, each of whom have their own economic circumstances, this IRP indicates Avista's most economic decision would be to close the plant at the end of 2025 as opposed to 2035[3]. To replace the lost Colstrip capacity along with the expiring Lancaster PPA, Avista seeks to add a combination of 175 MW of long duration pumped hydro and 200 MW of Montana wind. Absent a resource addition that is dependable on cold winter days, the ability to serve our customers is at great risk. Avista must acquire replacement generation with operational characteristics that enable the Company to serve our customers when they need it the most.

Avista is monitoring the potential for regional pumped hydro storage from several proposed projects with varying sizes and durations. Avista has an interest in pursuing one of these projects if the capacity and duration of the storage facility may help meet customers' winter peak load and if it exceeds the timing needs and pricing characteristics of alternative resources. Avista's analysis shows long duration storage assets may allow it to replace the need for natural gas-fired peaking generation identified in the previous IRP. Given the potential for storage, Avista considers it as part of its PRS and will actively pursue storage as long as it meets the needs of our customers in a reliable and cost effective manner. At any time, if Avista believes pumped storage is not feasible or cost effective, Avista may pursue other alternatives including a natural gas-fired peaker. To help with this decision making process, Avista may to issue a capacity RFP in 2021 to identify and compare all potential alternatives.

[3] From a regional reliability point of view, the plant would likely be better to close after the heating season ends in 2026. Avista expects this concern to be part of any closure decisions and should be a factor in policy decision making. Further, Avista did not model alternative closure dates in this IRP.

The 200 MW Montana wind resource would serve customers by adding potentially low cost clean energy as a contribution to meeting peak winter loads. This selection anticipates the utilization of the existing transmission currently used by Colstrip and would require this transmission capacity to be available. Any decision will likely result from an RFP in 2022 or 2023 to identify potential projects in either Montana or other locations with similar cost and operational attributes.

Existing Generation Project Upgrades

Avista is investigating the possibility of increasing the capacity of Kettle Falls by up to 12 MW by 2024. The Kettle Falls Generating Station is reaching the point where a repowering effort may be justified in lieu of replacing equipment in-kind. Similar to Kettle Falls, Avista will evaluate options to increase capacity at its Rathdrum CT site. Avista will work with the manufacturer and other vendors to identify potential methods to increase the capability of the plant. For planning purposes, this IRP estimates 24 MW of additional capacity, but that number could vary depending on the full evaluation of alternatives.

The Post Falls hydroelectric facility will also undergo modernization, leading to capacity improvements. At this point, the generating facilities are nearing the end of operating life, and Avista will need to decide to modernize by either replacing the generators and turbines with in-kind equipment or with equipment that increases the capacity of the facility. The IRP calculates an incremental capacity improvement as part of the overall modernization effort because it will increase the project’s capability and increase clean energy production while utilizing the same renewable resource.

2031-2040 Supply Side Resource Selection

The second decade of the IRP’s resource selection strategy is a continued effort to replace existing resource capacity, meet future load growth, and maintain resource adequacy. The complete list of resource additions for this decade is in Table 11.2. The first addition is a plan to replace the loss of our long-term regional hydro contracts with new contracts. Avista anticipates the potential for 75 MW of existing hydroelectric capacity to replace its expiring contracts. Existing hydroelectric generation will likely be competitive given 2031 is in the midst of the 80 percent requirement of CETA. Although capacity should be available, it will be a competitive process to acquire the generation.

The next resource selection is an upgrade or addition to the Long Lake Hydroelectric Development. This IRP identifies a need for this additional capacity to assist in meeting winter peak load and adding clean energy. Redevelopment of this project will require a long lead-time. The first step in this redevelopment is to certify the project as complying with the requirements of CETA. The need for this determination is due to language in CETA section 4 prohibiting new diversions, new impoundments, new bypass reaches, or expansion of existing reservoirs for qualifying resources. Avista believes an additional project at Long Lake meets the intent of the law, but would need a declaratory order before proceeding on the long permitting and construction process.

Table 11.1: 2020 Preferred Resource Strategy (2031-2040)

Resource	Time Period	ISO Conditions (MW)	Equivalent Winter Peak Capacity (MW)	Energy Capability (aMW)
Regional hydro PPA	2031	75	75	34
Long Lake upgrade/modernization	2035	68	68	23
Liquid air energy storage (LAES)	2036	25	15	n/a
Liquid air energy storage (LAES)	2038	25	15	n/a
Liquid air energy storage (LAES)	2040	25	15	n/a
Total		**218**	**188**	**57**

Assuming the Long Lake project is determined to qualify for CETA; Avista will need to determine the best method to increase the capability at the project. Avista has identified two alternatives requiring further study. The first alternative is a second powerhouse. Avista has studied this alternative since the 1970s. The second alternative is to create a new powerhouse with enough generating capability to retire the generating equipment in the existing powerhouse. The advantage of this alternative is the existing generation equipment is at the point it will require additional investment; this alternative could forgo the need to make such an investment. Both alternatives would install a new penstock at the location of the replacement for the saddle dam on the south end of the development. When the preferred alternative is decided, Avista will proceed with the CETA qualification review and the permitting process if warranted.

After 2035, Avista will require additional capacity to meet growing peak loads and the likely retirement of the Northeast CT. This IRP anticipates storage resources will be the economic choice in this period. At this time, using projected cost declines and required duration requirements for resource adequacy, Liquid Air Energy Storage (LAES) technology is the most likely option. Given the advancements in storage, the next 15 years of innovation may identify a lower cost option to meet customer needs. The requirements identify additional LAES in 2036, 2038, 2040, and 2041. It is likely the construction would be at one site with expansion capability as loads grow. Avista also recognizes the closure of the Northeast CT for driving the resource need and an earlier or later retirement of this resource will change the construction timetable for storage.

2041-2045 Supply Side Resource Selection

Avista typically does not forecast resource additions beyond 20 years. Given the CETA requirement to be 100 percent non-emitting by 2045, Avista concluded that modeling resources 25 years in the future had merit. The final five years of the plan, while relatively uncertain, identifies the need to replace existing renewable PPAs, with the addition of both renewable and storage technologies. Table 11.3 outlines these additions required to meet both energy and capacity requirements of Avista's customers.

Table 11.2: 2020 Preferred Resource Strategy (2041-2045)

Resource	Time Period	ISO Conditions (MW)	Equivalent Winter Peak Capacity (MW)	Energy Capability (aMW)
Liquid air energy storage	2041	25	15	n/a
NW wind	2042	100	5	37
4 hour storage (lithium-ion)	2042	25	3.75	n/a
NW wind	2043	100	5	37
4 hour storage (lithium-ion)	2043	100	15	n/a
Solar	2043	5	0.1	1.3
Solar w/ storage (50 MW x 4 hours)	2044	50	8.5	12
4 hour storage (lithium-ion)	2044	75	11.25	n/a
NW wind	2045	100	5	37
4 hour storage (lithium-ion)	2045	100	15	n/a
Total		**680**	**83.6**	**124.3**

Demand Response Selection

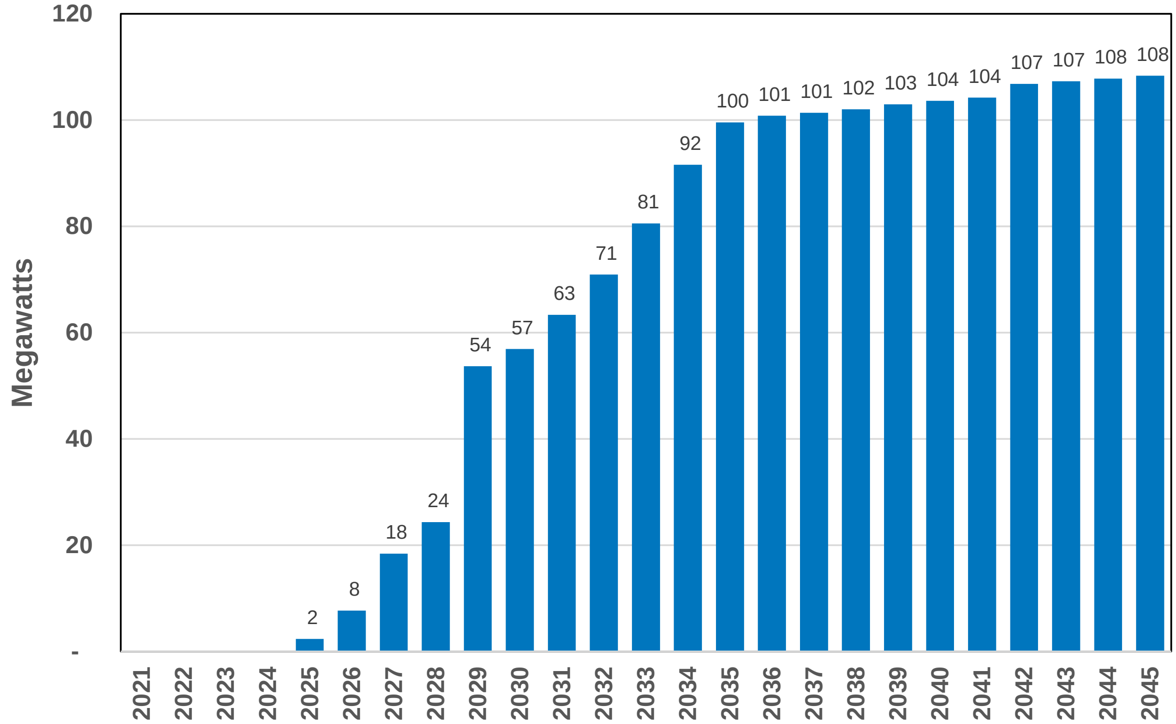
Demand Response (DR) will be an important part of Avista's strategy to satisfy customer's peak load requirements as generating resources leave the portfolio. Currently, Avista does not offer any load management programs, although it tested programs in the last few years. To understand the potential for new programs, Avista contracted with Applied Energy Group (AEG) to estimate the amount of DR available within the Idaho and Washington service territories. This process identified 17 potential programs to reduce 187 MW of winter peak load. Some programs offer reduction in both winter and summer, while others in only one season. Avista's forecasted needs are for winter peak reduction and several of the programs are cost effective. The first DR program selected in the PRS begins in 2025 and is likely to ramp into full capability by 2029. Table 11.4 shows each of the programs selected as part of the PRS and Figure 11.1 illustrates when DR enters the system and how the penetration of DR programs increases.

DR programs to meet reliability targets will depend on the length of time the program can reduce loads. For this IRP, Avista assumes a 60 percent peak credit. This is similar to the amount of an equivalent capacity DR program compared to an equal size natural gas-fired CT alternative. Due to the limited duration of the DR program, it only achieves 60 percent of the reliability benefits of a natural gas-fired CT. As Avista begins these DR programs, experience and program design will determine the ultimate capacity contribution to reliability. Further, the rate programs (time-of-use rates and variable peak pricing) are not dispatchable and any actual benefit will come from observation of the programs over time. DR programs may begin earlier than this IRP forecast as the 2021 Capacity RFP may highlight programs with cost effective potential prior to 2026. Certain programs may have a long lead-time to recruit enough participants in order to have sufficient DR capacity available.

Table 11.3: PRS Demand Response Programs

Resource	Start Year	Maximum Load Reduction (MW)
Variable peak pricing	2025	29.7
DLC smart thermostats	2029	18.9
Large C&I curtailment	2029	25.0
Time-of-use rates (opt in)	2032	8.3
Third party contracts	2032	23.1
Real-time pricing	2037	1.1
Ancillary services	2042	2.2
Total		**108.3**

Figure 11.1: Demand Response



Energy Efficiency Selection

The final resource as part of the PRS is energy efficiency. This IRP studied over 6,000 energy efficiency programs to reduce demand and offset the need for new generation. Avista models each of the programs individually to make sure to include each program's capacity and energy benefits in the analysis. This method allows for an accurate accounting of peak savings for energy efficiency that would not be included with programs modeled as buckets or compared to a levelized price of energy. In the midst of the IRP, Washington passed legislation effectively changing certain programs to codes and standards. This legislation reduces 2045 loads by six average megawatts from the more stringent codes and standards and is included in the energy efficiency selection.

As described in Chapter 3, the long-term energy and peak demand forecast already includes the benefits of energy efficiency. This requires adjustments to the load forecast to exclude the projected additions to energy efficiency so that potential specific programs selection can occur. This adjustment uses an iterative process in the PRiSM model. The process starts by adding back in the load represented by the prior 2017 IRP energy efficiency amounts to the load forecast. PRiSM then solves to add both supply-side and demand-side resources. The amount of selected energy efficiency changes as the amount of new energy efficiency added to the load forecast. Then the process repeats until the amount of energy efficiency selected and the amount of energy efficiency added to the load forecast is similar. Table 11.5 shows these amounts added to the load forecast and the ultimate amount of energy efficiency included in the PRS. The 187 aMW of savings amount includes transmission and distribution losses along with the six aMW from recent legislation for codes and standards. Avista expects total energy growth of 262 aMW between 2021 and 2045 with energy efficiency meeting 187 aMW. Energy efficiency is the primary resource to meet increases in customer's energy needs. Energy efficiency meets 71 percent of new load growth compared to 53 percent in the 2017 IRP.

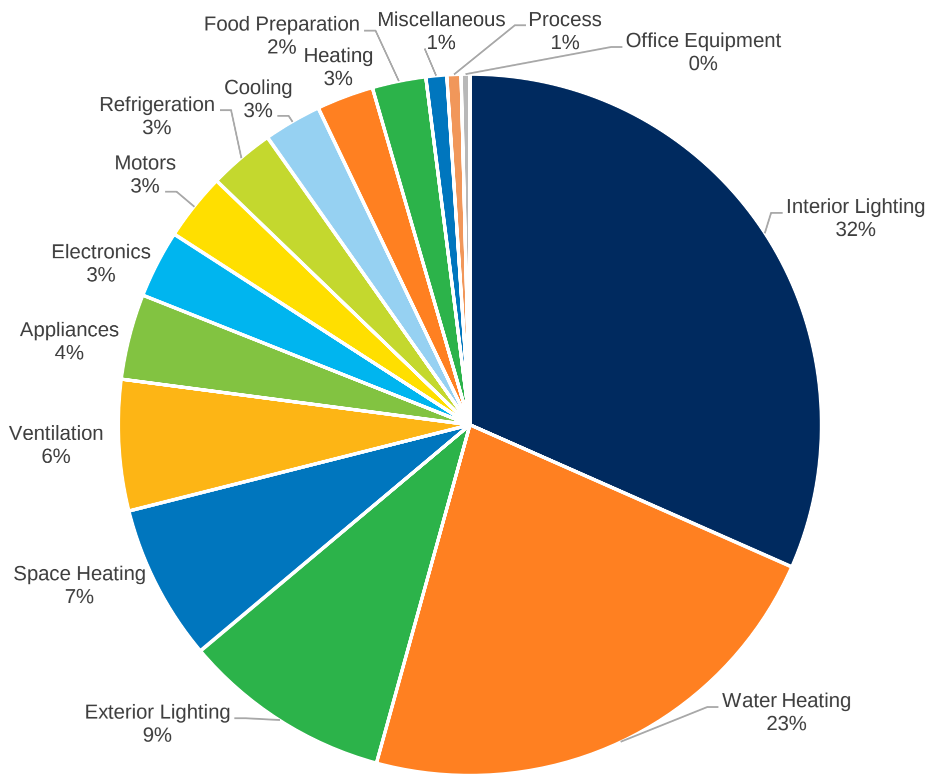
Table 11.4: Energy Efficiency Selected by PRiSM vs. Added to the Load Forecast

Year	EE Added to the Load Forecast	Selected EE from PRiSM
2021	6.1	6.0
2025	33.1	33.0
2030	72.0	72.1
2035	112.4	113.1
2040	149.4	150.9
2045	184.8	187.1

Over the course of the IRP planning horizon, 36 percent of new energy efficiency will come from Idaho customers and 64 percent from Washington customers. A majority of the savings will be from commercial customers (49 percent), followed by 41 percent from residential customers. The remaining savings will be from industrial customers. The greatest source of energy efficiency will come from lighting, and space and water heating. Figure 11.2 shows the program's share of the total savings to achieve the full 187.1 aMW of savings. The energy efficiency programs not only lower annual energy demand, they also reduce winter and summer peak demand. The selected programs lower winter peak load growth by 120 percent of its annual energy and summer peak loads by 133 percent of its annual average energy savings.

The amount of energy efficiency determined through this process will lead to program creation in both Washington and Idaho. The IRP informs the energy efficiency team to determine cost effective solutions and pursue new programs that may arise between IRP analyses.

Figure 11.2: Energy Efficiency Savings Programs



Reliability Analysis

For the first time, this IRP includes a reliability analysis of the PRS. The increasing amount of intermittent generation and storage included in the resource plan necessitated the need for a reliability analysis. Prior plans used only planning margin criteria along with reliable resource options to validate reliability. This plan uses a Loss of Load Probability Analysis (LOLP) to validate its reliability for the year 2030. This analysis uses the ARAM model. The model simulates 1,000 potential scenarios with different loads, wind estimates, hydro conditions, and forced outage rates for each hour. This analysis also includes existing resources expected to remain online in 2030 along with resource selections from this plan.

The objective of this plan is to have a LOLP of near 5 percent. This means up to 5 percent of the 1,000 simulations do not meet entire load requirements for the year. This methodology is similar to the concept of one resource adequacy issue in 20 years. The analysis compares this portfolio to alternative portfolios of existing resources with enough added combustion turbines to have a 5 percent LOLP. This allows for a comparison of reliability metrics compared to traditional resources and no resource additions. Table 11.6 shows this comparison. This analysis also assumes the ability to purchase short-term market power. Such market power purchases are limited to 250 MW in high-load periods, meaning temperatures below four degrees or above 84 degrees (daily average).

Table 11.5: 2030 Reliability Metrics

Year	Preferred Resource Strategy	350 MW Natural Gas CT	No Resource Additions
LOLP	5.3%	5.2%	54.3%
LOLH	2.02 hours	1.79 hours	50.8 hours
LOLE	0.18	0.14	3.71
EUE	330 MWh	264 MWh	10,092 MWh
Total Events	196	156	4,047

Without any new resources, we would have a greater than 50 percent probability of not being able to serve all loads in 2030. Both the PRS and 350 MW natural gas-fired alternatives have nearly 5 percent probability of an event meeting the criteria for resource adequacy. LOLP is the Northwest industry standard measurement of reliability, but other measurements may be necessary to validate resource needs for the system, especially as additional intermittent resources and storage enter the resource mix. The LOLP is really a measure of the frequency of a bad year. Other metrics are frequency of an event (LOLE)[4], duration of an event (LOLH)[5], and quantity of an event (EUE)[6]. It is possible Avista will consider utilizing some of these metrics in the future to measure reliability. Avista and other utilities are exploring regional resource adequacy targets and accountability. If the region can agree on the development of a regional resource adequacy program including the adoption of common reliability metrics and the ability to share reserves, Avista could require fewer total capacity resources in the near term or rely less on market purchases during extreme weather events.

Cost and Rate Projections

Avista typically only estimates costs related to existing and new resources as part of its IRP analysis. Under CETA in Washington, Avista must estimate total electric revenue requirements to determine if the cost of compliance exceeds CETA's 2 percent cost threshold over each of its four-year compliance periods beginning in 2030-2034. Estimating non-power supply related cost is outside the scope of the IRP, so for this calculation existing non-modelled costs inflate at 2 percent per year. This is the level of inflation used throughout the modeling process.

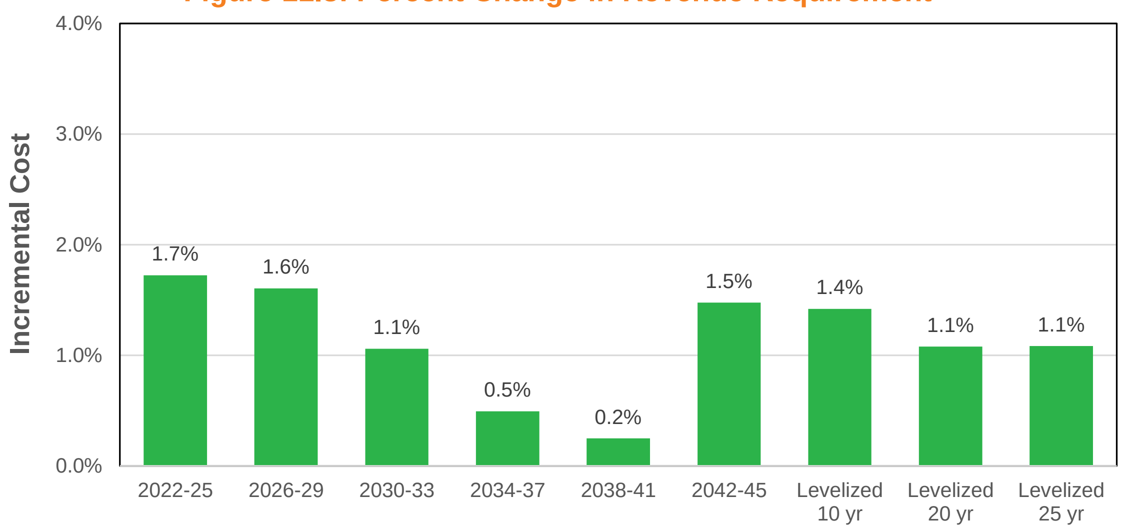
With CETA, it is important to understand the change in utility cost due to the policy. Specifically the provision to limit cost associated with its implementation, such as the 2 percent cost cap for meeting the 100 percent clean energy. This policy estimates rate increases in four-year increments. Figure 11.3 shows the estimates for cost increases for

[4] LOLE (Loss of Load Expectation) is defined by the total number of days within the 1,000 draws with unserved load dived by the number of draws (1,000).
[5] LOLH (Loss of Load Hours) is the average duration of the event measured by the number of hours of the outages.
[6] EUE (Expected Unserved Energy) is the average MWh of each event.

Avista's PRS in these increments. Over the 25-year period, costs are 1.4 percent higher for the system to comply with CETA as compared to a portfolio without CETA requirements. Avista found earlier investments in resources minimize the outer year cost increases. As 2045 approaches, meeting 100 percent of Washington energy needs will be difficult without new storage technology and the cost is likely to exceed the 2 percent cost cap. Avista did not model the 2045 portfolio to serve 100 percent of energy or allow the model to reach the 2 percent cost cap. Avista requires additional clarification and guidance from Washington Commission rulemaking to model the cost cap correctly.

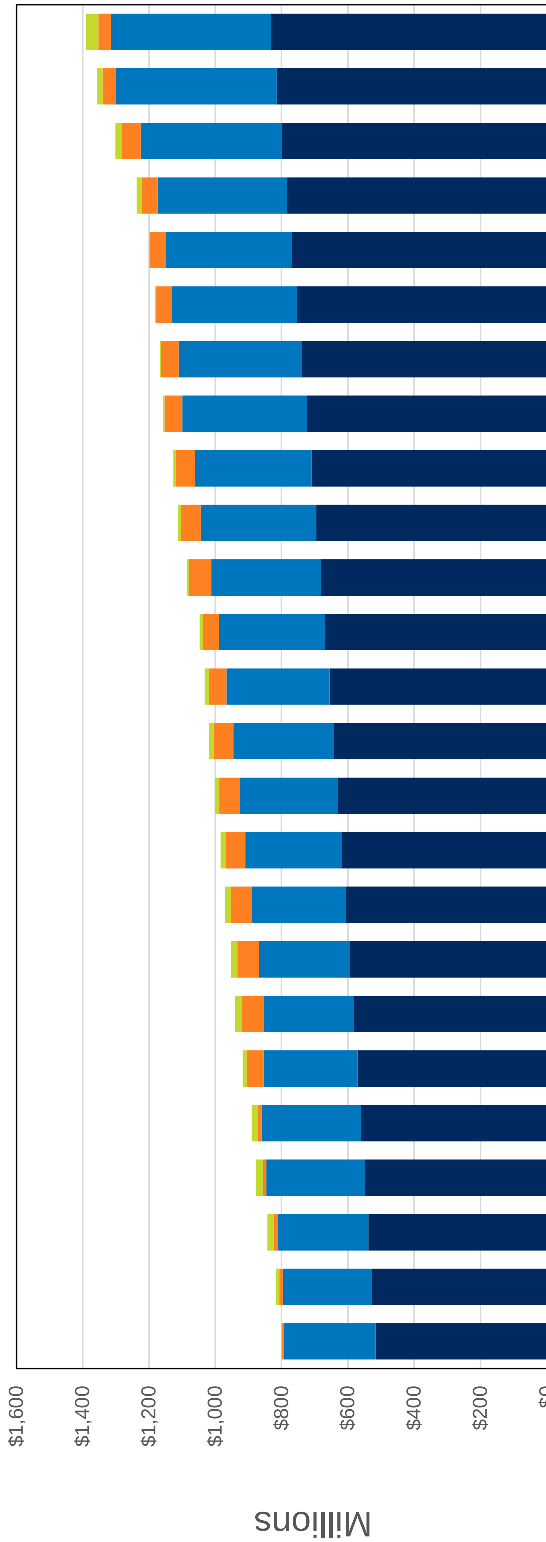
Figure 11.4 shows the forecast of annual power cost and average annual customer rates. The figure separates costs into four categories. The first is non-power related costs, estimated at $517 million[7] or 65 percent of the total customer rate in 2021. These costs include Fixed O&M related to Avista owned hydroelectric and biomass resources, distribution, transmission, and administrative and general expenses. The remaining costs are power supply related, including existing thermal generation, market transactions, contracts, new generation, new transmission for new resources, and energy efficiency. These cost categories are 1) the cost of existing generation and market transactions, 2) the cost to add capacity to serve the highest load hours, and 3) the added cost to comply with the CETA law in Washington. These added costs calculation compares the PRS to alternative portfolios. The present value of future revenue requirement for the 25 years is $11.8 billion. The existing resource cost and market transactions will contribute $3.7 billion to these estimates, while new capacity resource additions add $485 million, and the CETA requirements add $163 million. These costs lead to increases in customer rates of approximately 2 percent per year. Although power supply cost growth escalation is higher than 2 percent, the effect on overall rates is low given the relatively small contribution of power supply expense to the overall customer rate.

Figure 11.3: Percent Change in Revenue Requirement



[7] This estimate does not forecast what Avista's actual rates will be in 2021 and is an estimate for IRP analysis. This work does not include the level of scrutiny required for rate setting.

Figure 11.4: Utility Revenue Requirement



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Clean Energy	2	10	19	20	20	12	21	20	19	16	12	15	13
Capacity	5	11	11	11	10	51	67	64	63	59	63	60	53
Existing and Energy Only	276	268	275	297	301	283	271	275	283	291	295	303	311
Non- Power Related	517	527	538	548	559	571	582	594	606	618	630	643	656
Total Revenue Requirement	801	816	843	877	890	917	941	953	970	984	1,000	1,019	1,032
Rate Cents/kWh	8.7	8.8	9.1	9.4	9.5	9.8	10.0	10.1	10.3	10.4	10.5	10.7	10.8

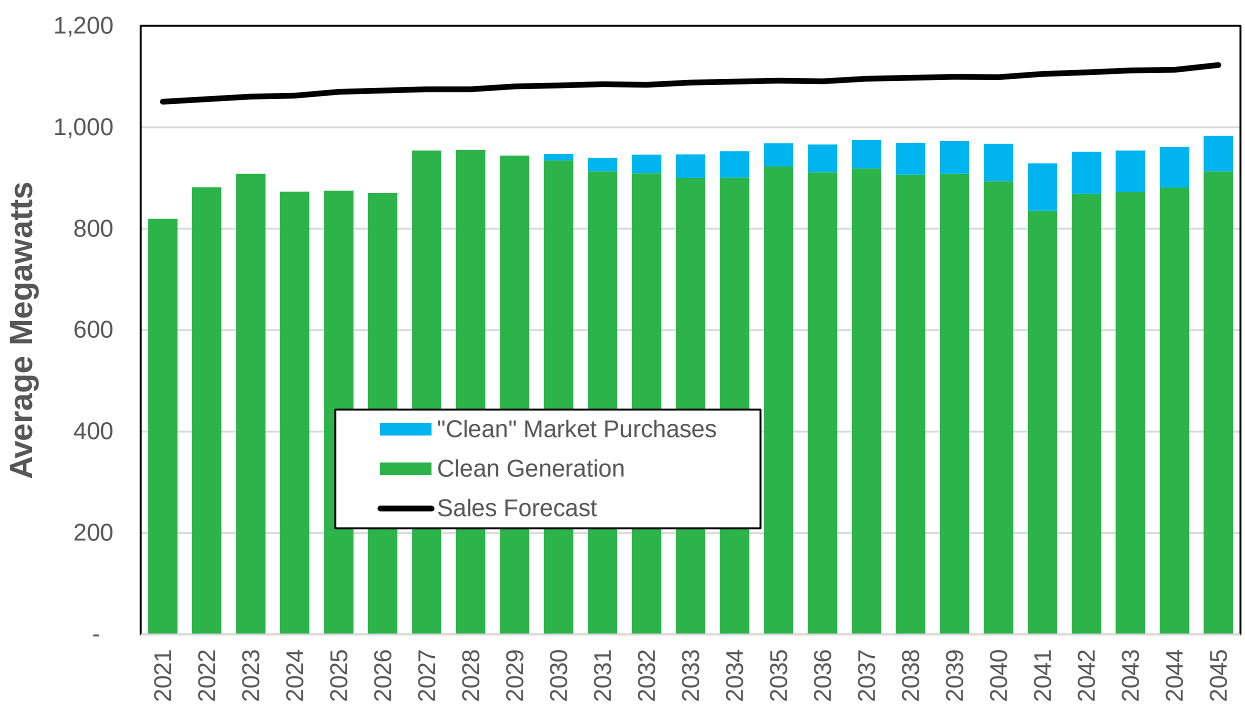
	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Clean Energy	10	7	9	8	5	4	3	3	16	20	18	38
Capacity	48	66	59	57	54	53	47	47	48	56	40	38
Existing and Energy Only	320	330	349	352	376	372	378	381	390	426	485	483
Non- Power Related	669	682	696	710	724	738	753	768	783	799	815	831
Total Revenue Requirement	1,047	1,085	1,113	1,127	1,158	1,167	1,182	1,200	1,238	1,302	1,357	1,390
Rate Cents/kWh	11.0	11.3	11.6	11.7	12.0	12.1	12.2	12.4	12.8	13.4	13.9	14.1

Environmental Analysis

Avista has a company-wide goal to serve all its customers with clean energy, specifically 100 percent of retail sales by net clean energy or emission offsets by 2027, and 100 percent of delivered energy by 2045. Avista is committed to this goal, and must balance this goal with state policies, affordability and reliability. Affordability is key to Avista's customers, most of whom have lower than state median household incomes. In addition, Avista customers live in areas subject to extreme winter and summer temperatures. CETA's cost cap provision reflects the need to balance the environmental and economic attributes of energy.

Avista's PRS meets 89 percent of the 2027 corporate goal, meaning nearly 90 percent of energy delivered on average will be from clean resources including hydroelectric, biomass, wind, and solar. Figure 11.15 shows the annual amounts. This estimate includes (shown in blue) the clean energy associated with market purchases. A future with more renewables and storage will require significant market interaction and regional cooperation to deal with the oversupply of intermittent generation and resource adequacy. As described in Chapter 10, the regional market will become cleaner as state laws require higher amounts of clean energy, coal plants close, and natural gas prices stay low. Avista estimates a portion of market transactions will be from clean resources. This estimate from the net amount of energy Avista purchases or sells each year and then applies the regional annual market emissions factor. With this factor, we can determine a split between clean and thermal generation purchases.

Figure 11.5: Annual Clean Energy



The PRS increases the amount of clean energy Avista serves to its customers and reduces its greenhouse gas emissions. Avista can estimate the amount of emissions associated with its owned generation based upon dispatch, but the amount of emissions from some market purchases are difficult to estimate because the generation sources cannot be determined, especially in power modelling. To estimate market purchase emissions, Avista uses the annual average regional emissions rate. For example, when Avista sells energy, the sales reduce Avista's emissions using the associated market rate or increase Avista's emissions by market rates for purchases. The market used for this analysis includes generation-related emissions from Washington, Idaho, Montana, Oregon, Utah, and Wyoming[8]. Chapter 10 covers these emission rates in further detail. For 2021, the greenhouse gas emissions rate is 672 pounds per MWh and by 2030, the rate falls to 426 pounds per MWh. These emissions are in the total net emissions calculation in Figure 11.6 in the dotted black line. These emissions also include purchased power associated for storage resources. The orange bars represent the expected emissions from current resources, while the yellow portion is from new resources. The solid line shows the actual emissions from Avista plans in 2018 as a comparison.

The 2030 emissions will be 79 percent lower than the 2018 levels and 85 percent lower by 2045. The major emissions reductions come from the removal of Colstrip and Lancaster from the system along with reductions in natural gas-fired dispatch. Another point of interest is the regional change in emissions from electrification of the transportation system. Avista's current load forecast used in the PRS includes 100,000 vehicles converting from petroleum. This conversion reduces regional economy-wide emissions and transfers vehicle charging onto the electric system, resulting in lower emission rates. To illustrate this impact, the solid black line in Figure 11.6 shows the reduction in vehicle emissions, which is greater than the total emission from Avista's power supply by 2045.

Another measure of emissions is emissions intensity. This is the net emissions from Figure 11.6 divided by retail sales. For 2021, this is 461 pounds per MWh. By 2040, this amount will decline to approximately 100 pounds per MWh. This data is in Figure 11.7. As a comparison, Avista's current emissions intensity as reported by the Washington State Department of Commerce for Washington retail sales is 565 pounds per MWh.

[8] Avista believes this footprint is beyond where Avista can acquire power from, but is consistent with methodologies currently used in Washington State fuel mix reporting. This may also change with rulemaking underway.

Figure 11.6: Greenhouse Gas Emissions

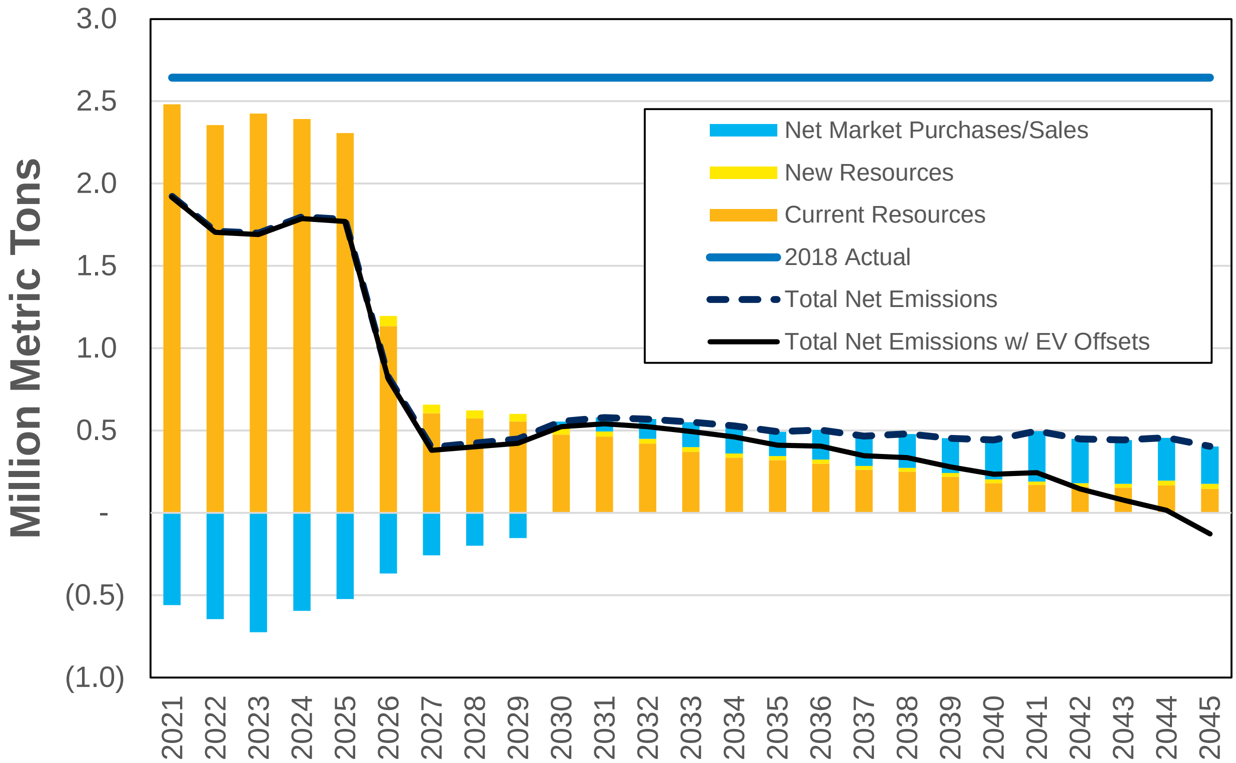
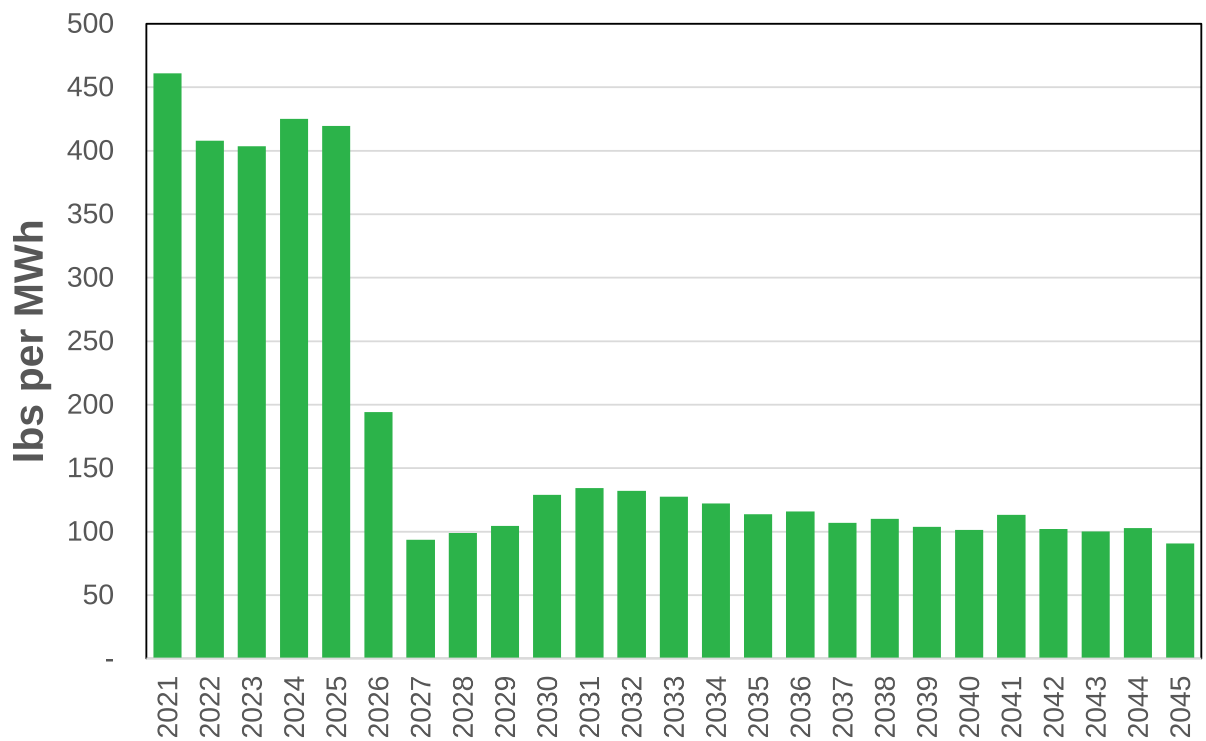
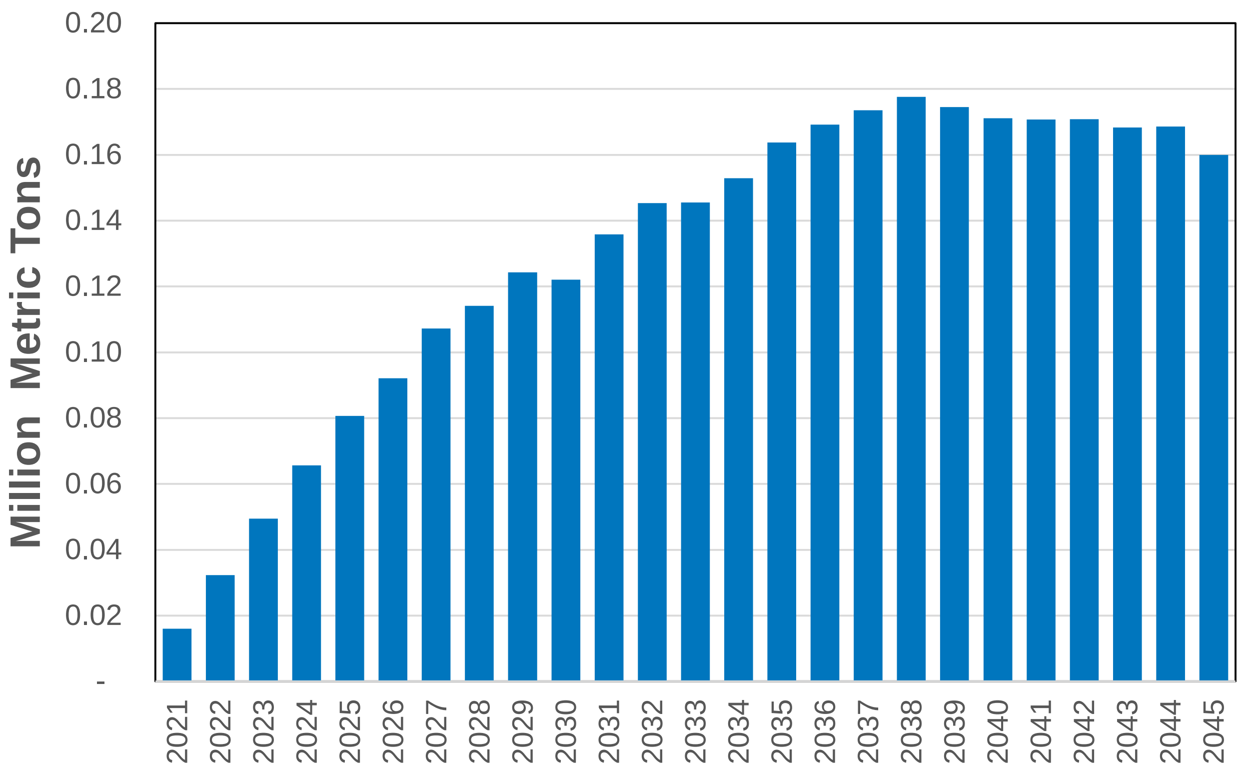


Figure 11.7: Total Net Greenhouse Gas Emissions Intensity



Avista's energy efficiency programs also reduce regional emissions and therefore an estimate of the emissions avoided by energy efficiency needs to be calculated. There are many methods to estimate the "avoided emissions" associated with energy efficiency, but Avista chose to use the annual average market rate of emissions per MWh for this calculation. The reason for this choice is the change in load requires a market response of generation rather than just the individual utility; therefore, with less load, the utility and the region will have lower emissions. Avista believes this method properly estimates the change in emissions. For this analysis, each MWh of energy efficiency reduces regional emissions by the market rate (Chapter 10- Figure 10.14). This reduction feeds into the optimization of resources and the Washington State requirement to use the social cost of carbon benefits of energy efficiency. The estimated savings are not included in Figure 11.6 above because of their inclusion in the net emissions to serve net load. The calculation helps to understand the benefit of the emission reduction from energy efficiency. Figure 11.8 shows the annual avoided greenhouse gas emissions from energy efficiency. Over the 25-year forecast, Avista's energy efficiency programs reduce regional emissions by 3.25 million metric tons between 2021 and 2045.

Figure 11.8: Energy Efficiency GHG Emissions Savings

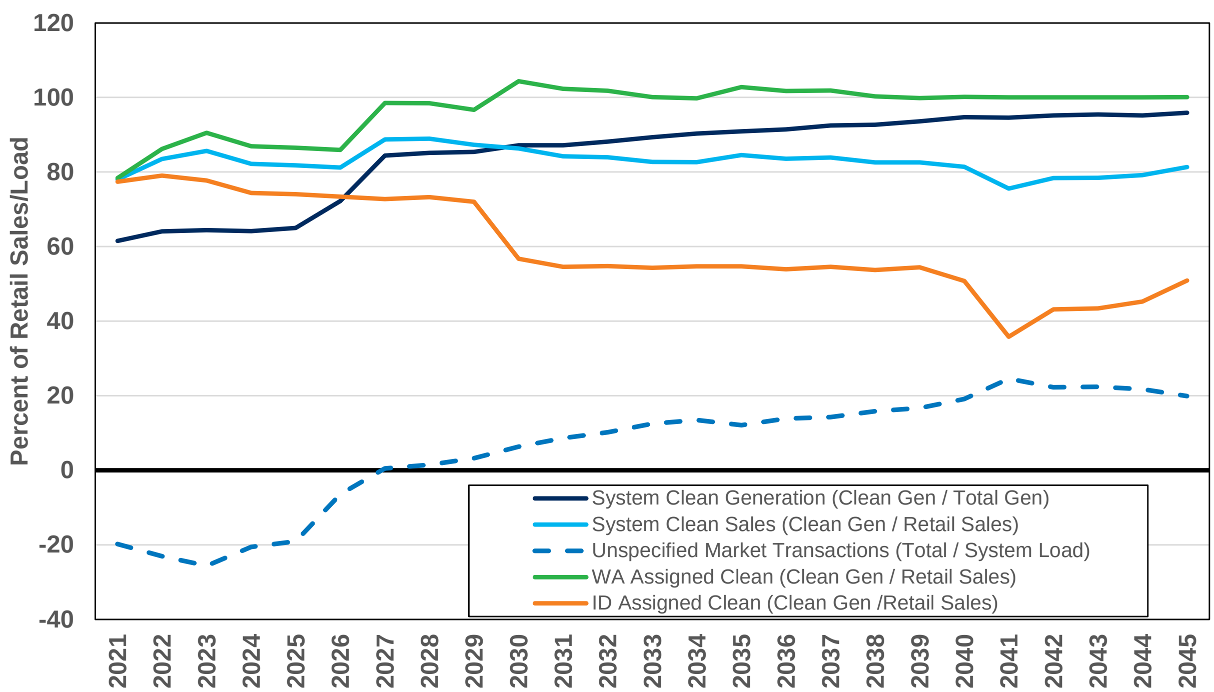


For resource optimization, this analysis includes the upstream emissions content from the natural gas supply chain. Upstream emissions come from the drilling, processing, and transportation of the natural gas to end use customers. Avista sources its natural gas for power entirely from the Canadian system. As described in Chapter 9, the upstream emissions factor for our natural gas purchases is 0.784 percent including the associated multipliers for methane release. These emissions are included in the optimization of resource choices, but are not included in the estimate shown in Figure 11.7. Avista estimates these emissions to be 10,000 metric tons in 2020 and 1,160 metric tons by 2045. Lower natural gas usage is the driver from lower upstream emissions.

Another metric to view Avista's clean energy resource mix is to account for transfers of clean energy between states (see Figure 11.9). The figure shows several different clean energy measures to illustrate how energy serves customers in each state and as a system. The dark blue line is "System Clean Generation (Clean Gen / Total Gen)" it estimates the amount of clean generation as compared to Avista's controlled generation, this metric shows Avista's system clean generation mix.

The light blue line "System Clean Sales (Clean Gen / Retail Sales)" shows the amount of clean generation as compared to annual system retail sales. Any remaining power to serve customers is from market transactions or from other generation. The dotted blue line estimates the amount of net market transactions and is labeled "Unspecified Market Transactions (Total / System Load)." Clean energy assigned to Washington for CETA compliance is the green line "WA Assigned Clean (Clean Gen / Retail Sales)" and the remaining clean energy for Idaho is the orange line "ID Assigned Clean (Clean Gen / Retail Sales)." Lastly, this chart does not forecast any REC sales to non-Avista customers.

Figure 11.9: Clean Energy Mix Forecast



Avoided Cost

As part of the IRP process, Avista calculates the avoided or incremental cost to serve customers by comparing the PRS cost to alternative portfolios. There are two important avoided cost calculations: the first is for new generation resources and the second is for energy efficiency.

New Resource Avoided Cost

The 2020 IRP's avoided costs are in Table 11.6. However, avoided costs will change as Avista's loads and resources change, as well as with changes in the wholesale power marketplace. Avoided Costs use the best available estimate at the time of the analysis with the data available. Any precise or specific project characteristics will likely change the value of a resource. The prices shown in the table represent energy and capacity values for different periods and product types, including renewable energy projects. For example, a new generation project with equal deliveries over the year in all hours has an energy value equal to the flat energy price shown in Table 11.6. The table also includes traditional on-peak and off-peak pricing as a comparison to the flat price. In addition to the energy prices, this theoretical resource would also receive the capacity value as it produces power at the time of system peak. This system peak contributing value begins in 2026 for resources that can dependably meet winter peak requirements.

Capacity value is the resulting marginal cost of capacity each year. Specifically, the calculation compares a higher cost of a portfolio with new capacity against a lower cost portfolio with no new resources for each year. Avista uses these annual cash flow differences to create an annualized cost of capacity beginning the first year the utility is short with an annual price adjustment of 2 percent per year. This calculation removes the variability in annual payments but is the same present value cost. The next step divides the cost by the amount of added capacity in terms of winter peak. This value is the cost of capacity per MW, or cost per kW-year. The capacity payment applies to the capacity contribution of the resource at the time of the winter peak hour.

To obtain a full capacity payment, the resource must generate 100 percent of its capacity rating at the time of system peak. For example, solar receives a 2 percent credit based on ELCC analysis and would receive 2 percent of the capacity payment as compared to its operational capacity. For wind resources, their location determines the capacity credit they receive. Northwest wind contributes 5 percent of its operational capacity to winter peaks, while Montana wind contributes 40 percent. No matter the resource, Avista will need to conduct an ELCC analysis for any specific project it evaluates to determine its peak credit. Another item to consider for intermittent resources is the cost to integrate the variability onto the system. Any potential resource seeking Avoided Cost pricing shall reduce its compensation by these integration costs.

The clean energy premium calculation is similar to the capacity credit, but in this instance, it estimates the cost to comply with CETA by comparing the PRS to a portfolio without complying with CETA. Chapter 12 discusses these portfolios. Avista uses these annual cash flow differences to create an annualized cost of capacity beginning with the first year of clean energy acquisition with an annual price adjustment of 2 percent per year. Then the new annual cost divided by the incremental megawatt hours of generation. This value shows the amount of extra cost per MWh to meet CETA[9]. This benefit includes the cost associated with changing to cleaner capacity resources but also adding clean energy resources.

A scenario is also included to highlight the Clean Premium for projects if federal tax credits continue (see Table 11.7). In this scenario, the incremental cost of clean energy is lower due to the cost shift from utility customers to tax payers. The clean premium estimate for specific future projects will depend on the amount of clean energy and clean capacity the asset produces.

Avista believes the best method for estimating avoided costs of new clean energy resources is through the RFP process. An RFP process provides real cost information with specific energy resources. These pricing results are the real avoided costs if Avista were to acquire additional clean energy resources. For capacity resources, an RFP is also the best method for determining these costs. Although certain cases, specifically acquiring hydroelectric existing resources may not be available in an RFP process, and Avista must use judgement and market intelligence when acquiring these resources to ensure they are at competitive prices.

Energy Efficiency Avoided Cost

The energy efficiency avoided cost is useful for the energy efficiency evaluation and acquisition team to conduct financial analysis of potential programs in between IRP analyses. The process to estimate avoided cost calculates the marginal cost of energy and capacity of the resources selected in the PRS. The calculation process is similar to the generation resources above, but differs in the case of energy efficiency. In this scenario, the model disables the option to use energy efficiency as a resource. This method results in the total benefit energy efficiency brings to the system.

Unlike generation resources, the energy efficiency avoided costs include additional premium components. First is the 10 percent NPCC preference adder. Second is the consideration of transmission and distribution losses. Third is savings of constructing less transmission and distribution facilities. The social cost of carbon is also included for project evaluation in Washington. For this example, the social cost of carbon applies to the projected greenhouse gas savings from the market transactions as described above. For avoided cost purposes, this consideration is included in the clean energy premium. In summary, energy efficiency avoided cost is the first value of the saved energy. The second is the savings in capacity resources as defined by the difference between a portfolio meeting only capacity requirements and no capacity obligations. Third, is the incremental cost to meet the clean energy requirements of CETA. This includes the value

[9] Avista is modeling the CETA premium as an energy payment for Avoided Cost. Analysis shows the CETA premium actually changes some capacity decisions and theoretically, some of the clean energy premium should be associated with capacity for clean energy resources. This also assume Idaho's share of the hydroelectric system does not contribute to Washington's 100 percent goals, with the exception of alternative compliance limited to 20 percent in 2030.

of less clean energy resources required by energy efficiency effect of lowering load and the reduction in greenhouse emissions. Figure 11.9 shows each of these cost estimates below.

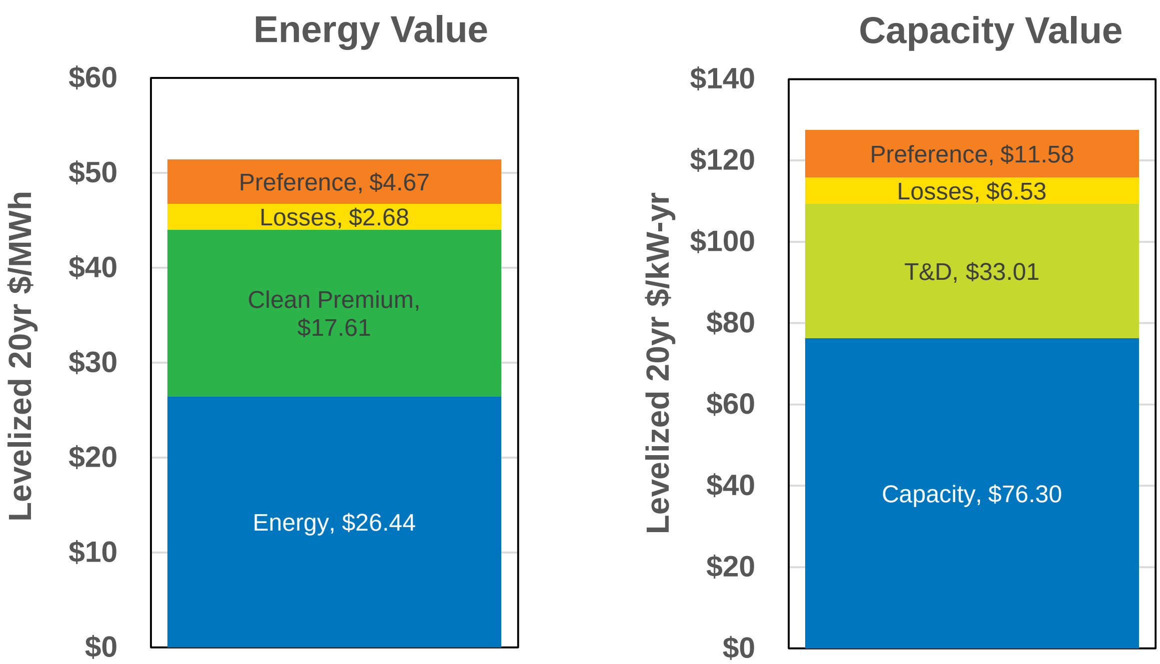
Table 11.6: New Resource Avoided Costs

Year	Energy Flat (MWh)	Energy On-Peak (MWh)	Energy Off-Peak (MWh)	Clean Premium (MWh)	Capacity ($/kW-Yr)
2021	19.67	22.64	15.71	0.00	0.0
2022	19.98	22.75	16.28	11.75	0.0
2023	20.44	23.05	16.98	11.99	0.0
2024	21.61	24.09	18.28	12.23	0.0
2025	22.76	25.19	19.50	12.47	0.0
2026	24.27	26.40	21.43	12.72	107.7
2027	23.57	25.27	21.30	12.97	109.9
2028	25.02	26.26	23.35	13.23	112.1
2029	25.92	26.80	24.73	13.50	114.3
2030	26.72	27.08	26.25	13.77	116.6
2031	29.46	29.66	29.21	14.04	118.9
2032	29.78	29.95	29.54	14.32	121.3
2033	31.22	30.74	31.89	14.61	123.7
2034	32.83	31.94	34.06	14.90	126.2
2035	33.66	32.64	35.05	15.20	128.7
2036	35.82	34.82	37.16	15.51	131.3
2037	36.12	34.58	38.19	15.82	133.9
2038	38.81	37.40	40.76	16.13	136.6
2039	38.60	37.13	40.57	16.45	139.3
2040	38.52	36.80	40.84	16.78	142.1
2041	39.09	37.74	40.92	17.12	145.0
2042	38.98	37.99	40.31	17.46	147.9
2043	40.24	39.51	41.21	17.81	150.8
2044	46.10	45.29	47.15	18.17	153.9
2045	43.94	43.11	45.05	18.53	156.9
15 yr Levelized	24.58	26.11	22.55	11.81	64.8
20 yr Levelized	26.44	27.55	24.98	12.43	75.1
25 yr Levelized	27.86	28.77	26.66	12.93	82.2

Table 11.7: New Resource Avoided Costs With Renewable Tax Credits

Year	Energy Flat (MWh)	Energy On-Peak (MWh)	Energy Off-Peak (MWh)	Clean Premium (w/ Tax Incentive) (MWh)	Capacity ($/kW-Yr)
2021	19.67	22.64	15.71	0.00	0.0
2022	19.98	22.75	16.28	3.44	0.0
2023	20.44	23.05	16.98	3.50	0.0
2024	21.61	24.09	18.28	3.57	0.0
2025	22.76	25.19	19.50	3.65	0.0
2026	24.27	26.40	21.43	3.72	107.7
2027	23.57	25.27	21.30	3.79	109.9
2028	25.02	26.26	23.35	3.87	112.1
2029	25.92	26.80	24.73	3.95	114.3
2030	26.72	27.08	26.25	4.03	116.6
2031	29.46	29.66	29.21	4.11	118.9
2032	29.78	29.95	29.54	4.19	121.3
2033	31.22	30.74	31.89	4.27	123.7
2034	32.83	31.94	34.06	4.36	126.2
2035	33.66	32.64	35.05	4.44	128.7
2036	35.82	34.82	37.16	4.53	131.3
2037	36.12	34.58	38.19	4.62	133.9
2038	38.81	37.40	40.76	4.72	136.6
2039	38.60	37.13	40.57	4.81	139.3
2040	38.52	36.80	40.84	4.91	142.1
2041	39.09	37.74	40.92	5.01	145.0
2042	38.98	37.99	40.31	5.11	147.9
2043	40.24	39.51	41.21	5.21	150.8
2044	46.10	45.29	47.15	5.31	153.9
2045	43.94	43.11	45.05	5.42	156.9
15 yr Levelized	24.58	26.11	22.55	3.45	64.8
20 yr Levelized	26.44	27.55	24.98	3.63	75.1
25 yr Levelized	27.86	28.77	26.66	3.78	82.2

Figure 11.10: Avoided Cost of Energy Efficiency



12. Portfolio Scenario Analysis

The Preferred Resource Strategy (PRS) is Avista's 25-year strategy to meet future loads and replace generation resources. Because the future is often different from the IRP forecast, the strategy needs to be flexible to serve customers under a range of plausible outcomes. This IRP identifies many permutations of potential resource strategies due to availability and pricing. Further, resource decisions may change depending on how customers use electricity, how the economy changes, and how carbon emission policies evolve. This chapter investigates the cost and risk impacts to the PRS under different futures the utility might face as well as alternative resource portfolios.

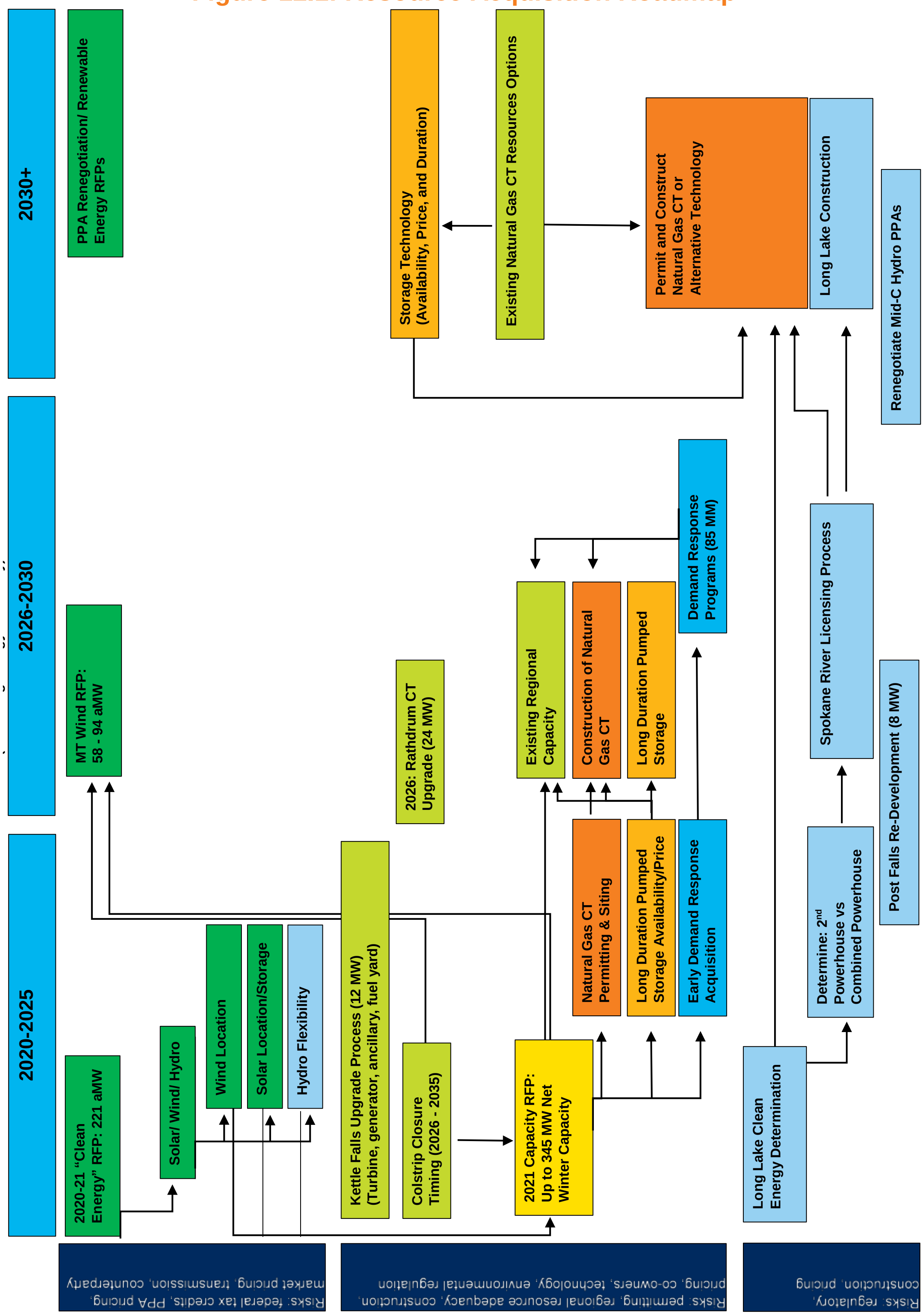
Chapter Highlights

- Colstrip is more economically retired at the end of the 2025/26 heating season as compared to 2035.
- The PRS, compared to a portfolio without CETA, includes an implied carbon price of $55 per metric ton.
- Electrifying the space and water heating system exceeds the social cost of carbon.
- Electrifying the transportation system leads to significant regional emissions- but will increase utility emissions.

The 2020 PRS is Avista's preferred resource plan, but plans may change as alternative pricing and resource availability is determined in future RFPs. Avista's IRP is a roadmap of potential resource acquisition strategies using currently known information. For example, how will our resource strategy change if pumped storage or Long Lake 2 is not an economically viable resource alternative, or if the Lancaster PPA extends beyond 2026? This chapter covers potential alternative portfolios including different Colstrip shutdown dates, higher and lower load forecasts, tax credit scenarios, and the costs of implementing the 100 percent clean energy corporate goal. Figure 12.1 shows how resource decisions may change depending on future events and how resource decisions may interact with each other.

In addition to alternative portfolio choices, Avista also tested the portfolios with alternative market futures. These scenarios show how the portfolios fare against each other with a carbon tax, if natural gas prices were higher or lower, or if the costs of complying with CETA in Washington were removed. In addition to these market scenarios, this chapter shows how the portfolios perform when considering the 500 iterations of market futures, which portfolios have lower risk, and what is the cost to reduce risk. Lastly, this chapter covers a scenario where a major shift to electrification from fossil fuels begins. In this scenario, space and water heating begins to shift to electric rather than natural gas, transportation electrifies, and additional homes well beyond the current rate of adoption install rooftop solar panels. This scenario outlines the grid impacts, costs, and environmental impacts of as an electrification policy.

Figure 12.1: Resource Acquisition Roadmap



Portfolio Scenarios

Avista studied 15 alternative portfolios to compare cost, risk, and emissions to the PRS. The PRS is portfolio #1 on all tables and charts in this chapter. The remaining portfolios change assumptions to arrive at a portfolio to meet a specific objective. The next section outlines each of the portfolio objectives and resource selection. The resource selections included in the PRS are in Table 12.1.

Table 12.1: Portfolio #1- Preferred Resource Strategy

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2022-2023	200
Kettle Falls upgrade	2026	12
Colstrip 3 & 4 exits portfolio	2026	-222
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	175
Lancaster PPA expires	2026	-257
Post Falls upgrade	2027	8
Montana wind	2027	200
Mid-Columbia hydro	2031	75
Northeast CTs retires	2035	-55
Long Lake 2nd powerhouse	2035	68
Liquid-air storage (16 hours)	2036-2041	100
Wind (including PPA renewals)	2041-2043	300
Lithium-ion storage (4 hour)	2042-2045	300
Solar w/ storage (4 hours)	2044	55
4-hr Storage for Solar	2044	50
Supply-side resource net total (MW)		1,133
Supply-side additions through 2045 (MW)		1,667
Demand Response through 2045 (MW)		112
Energy Efficiency through 2045 (aMW)		187

Portfolio #2: Least Cost Plan- without CETA

This portfolio has many objectives. First, to understand how the utility would plan its portfolio prior to CETA's inception in Washington. It allows Avista to identify the incremental cost of CETA and develop the 2 percent rate cap analysis within CETA. It is used for avoided cost calculations of clean energy and could potentially be used to identify resource cost allocation for resources acquired for one of Avista's two states it serves. The specific resource selection for this portfolio is in Table 12.1. The major differences between this portfolio and the PRS are this portfolio includes fewer new wind resources, the inclusion of natural gas CTs, and no Long Lake 2.

Table 12.2: Portfolio #2- Least Cost Plan- without CETA

Resource Type	Year	Capability (MW)
Montana wind	2022	100
Kettle Falls upgrade	2026	12
Colstrip 3 & 4 exits portfolio	2026	-222
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	200
Lancaster PPA expires	2026	-257
Post Falls upgrade	2027	8
Natural Gas CT	2027	92
Mid-Columbia hydro	2031	75
Northeast CTs retires	2035	-55
Liquid-air storage (16 hours)	2038	25
Lithium-ion storage (4 hours)	2039	25
Liquid-air storage (16 hours)	2040-42	75
Natural gas CT	2043	55
Lithium-ion storage (4 hour)	2045	53
Supply-side resource net total (MW)		210
Supply-side additions through 2045 (MW)		744
Demand Response through 2045 (MW)		87
Energy Efficiency through 2045 (aMW)		166

Portfolio #3: Clean Energy Plan (CEP)

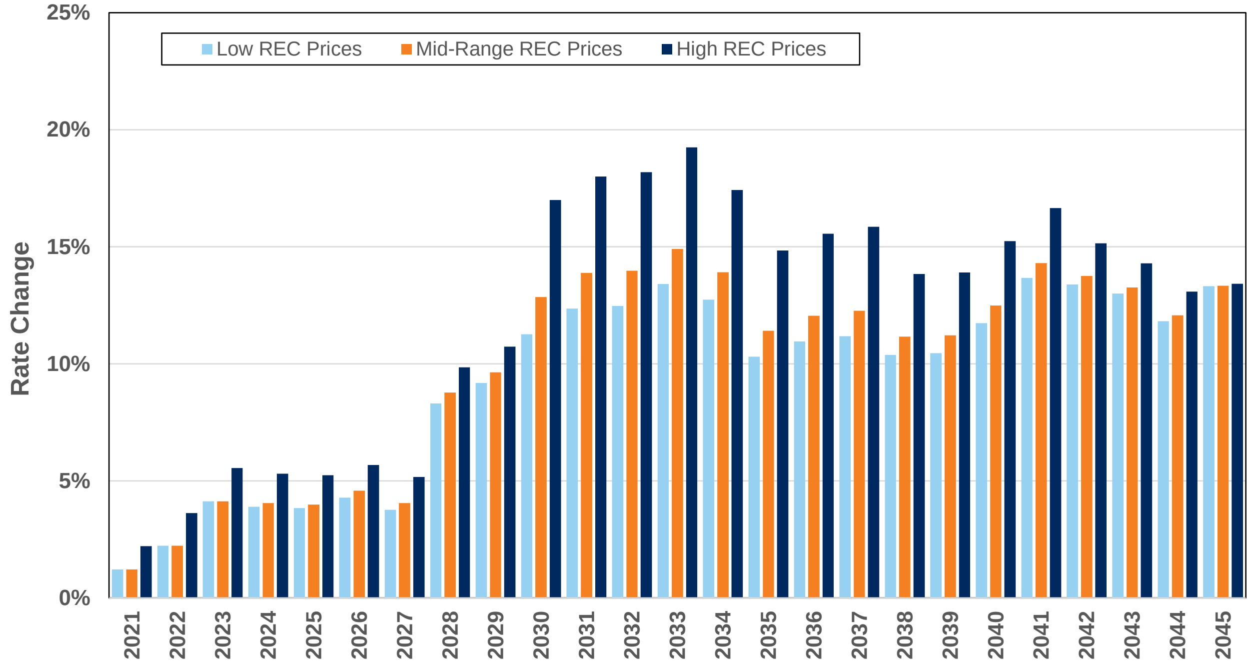
This portfolio identifies the resource acquisition steps and cost implications with Avista achieving 100 percent net clean energy by 2027 for all customers. This portfolio does not attempt to serve 100 percent of load every hour of the year with non-fossil fuels or purchase Renewable Energy Credits. This portfolio requires additional resources to serve Idaho retail sales with clean energy. This assumption would eliminate Idaho's ability to sell its clean energy attributes to either Avista's Washington customers or other utilities.

Table 12.3: Portfolio #3- Clean Energy Plan

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW solar	2022	150
NW wind	2023	200
Kettle Falls upgrade	2024	12
Colstrip 3 & 4 exits portfolio	2026	-222
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	125
Lancaster PPA expires	2026	-257
Montana wind	2026	200
Post Falls upgrade	2027	8
NW Solar	2027-2030	325
Geothermal	2029	20
Mid-Columbia hydro	2031	75
Long Lake 2nd powerhouse	2031	68
Northeast CTs retires	2035	-55
Solar w/ 150 MW storage (4 hours)	2033-2040	195
Wind (including PPA renewals)	2041-2043	300
Liquid-air storage (16 hours)	2042	25
Lithium-ion storage (4 hours)	2043-2045	225
Solar w/ storage	2040-2045	70
Storage for solar (4 hours)	2045	50
Supply-side resource net total (MW)		1,638
Supply-side additions through 2045 (MW)		2,172
Demand Response through 2045 (MW)		111
Energy Efficiency through 2045 (aMW)		213

Avista conducted a state specific study with this scenario where it compares the allocated cost to Idaho compared to the PRS. In this case, the Idaho customers pay only the allocated cost from Portfolio #2, and Washington customers pay all incremental costs from the PRS. Idaho would not sell its excess RECs to Washington or any other buyer in this scenario. This rate comparison shown in Figure 12.2 is for three REC price scenarios. The first scenario is RECs remain at $4 per MWh for the whole period. REC prices are $6.40 in the second scenario, and REC prices increase to $15.40 per MWh in the high price scenario. This analysis shows Idaho rates will increase approximately 5 percent until 2027 and between 12 and 20 percent higher between 2030 and 2035 due to the clean energy goal.

Figure 12.2: Idaho Clean Energy Plan Rate Impacts



Portfolio #4: Rely on Energy Market Only

This portfolio estimates the cost to serve only the energy portion of power supply, allowing for the calculation of the cost of capacity. Further, this portfolio shows what resource additions are cost effective based on energy alone. The results show the Post Falls hydroelectric upgrade and 127 aMW of energy efficiency are the lowest cost resource alternatives.

Table 12.4: Portfolio #4- Clean Energy Plan

Resource Type	Year	Capability (MW)
Colstrip 3 & 4 exits portfolio	2026	-222
Lancaster PPA expires	2026	-257
Post Falls upgrade	2027	8
Northeast CTs retires	2035	-55
Supply-side resource net total (MW)		-526
Supply-side additions through 2045 (MW)		8
Demand Response through 2045 (MW)		0
Energy Efficiency through 2045 (aMW)		127

Portfolio #5: 100 Percent Net Clean and No CTs by 2045

This portfolio attempts to estimate costs to serve the capacity in addition to energy with all clean resources. Avista has not conducted a reliability analysis of this portfolio to determine if it satisfies the 5 percent LOLP requirement although uses the same planning margin target as the PRS. The model increases both renewables and storage along with “clean” baseload resources from geothermal, biomass, and nuclear. The model may select additional hydroelectric upgrades, such as the Monroe Street upgrade, as well if available.

Table 12.5: Portfolio #5- CEP and No CTs by 2045

Resource Type	Year	Capability (MW)
NW solar	2022	150
MT wind	2022	100
NW wind	2023	200
Kettle Falls upgrade	2024	12
Colstrip 3 & 4 exits portfolio	2026	-222
Long duration pumped hydro	2026	150
MT wind	2026	200
Lancaster PPA expires	2026	-257
Post Falls upgrade	2027	8
NW solar	2027-2030	325
Geothermal	2029	20
Mid-Columbia hydro	2031	75
Long Lake 2nd powerhouse	2031	68
NW solar	2033	55
Northeast CTs retires	2035	-55
NW solar w/ storage	2036-2040	140
Storage for solar (4 hours)	2036-2040	125
Liquid air storage (16 hours)	2040	200
Pumped hydro	2040	75
Rathdrum CTs removed	2040	-154
Wind (including PPA renewals)	2041-2043	300
Kettle Falls CT removed	2043	-9
Boulder Park removed	2043	-25
Liquid air storage (16 hours)	2042-2044	125
Lithium-ion storage (4 hours)	2043-2045	28
Coyote Springs 2 removed	2045	-302
NW solar w/ storage	2044-2045	130
Storage for solar (4 hours)	2044-2045	75
Pumped hydro	2045	225
Small nuclear	2045	100
Biomass	2045	50
Supply-side resource net total (MW)		1,912
Supply-side additions through 2045 (MW)		2,936
Demand Response through 2045 (MW)		108
Energy Efficiency through 2045 (aMW)		214

Portfolio #6: Least Cost Plan w/o Pumped Hydro or Long Lake Upgrade

The PRS includes some level of risk of two major resources not being able to be either constructed when needed or even able to be constructed at all due to licensing constraints. This portfolio estimates Avista's resource plan if long duration pumped hydro[1] or the Long Lake upgrade are not available due to any reason, the net result of these changes is a need for 245 MW of natural gas-fired CTs and shifting 200 MW of Montana wind to 2035 to coincide with the retirement of the Northeast CT.

Table 12.6: Portfolio #6- LC without Pumped Hydro or Long Lake Upgrade

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2022-2023	200
Kettle Falls upgrade	2026	12
Colstrip 3 & 4 exits portfolio	2026	-222
Rathdrum CT 1 & 2 upgrades	2026	24
Natural Gas CT	2027	245
Lancaster PPA expires	2026	-257
Post Falls upgrade	2027	8
Mid-Columbia hydro	2031	75
Northeast CTs retires	2035	-55
Montana wind	2035	200
Liquid-air storage (16 hours)	2038-2041	75
Wind (including PPA renewals)	2041-2043	300
Lithium-ion storage (4 hour)	2044-2045	150
Liquid-air storage (16 hours)	2043	25
Solar w/ storage	2045	100
Storage for solar (4 hours)	2045	100
Geothermal	2045	20
Supply-side resource net total (MW)		1,100
Supply-side additions through 2045 (MW)		1,634
Demand Response through 2045 (MW)		108
Energy Efficiency through 2045 (aMW)		177

[1] Excludes the 40 and 80-hour options, but allows PRiSM to select 8. 16, and 24-hour projects if cost effective.

Portfolio #7: Least Cost Plan with Colstrip extended to 2035, without CETA

If shutdown dates for Colstrip Units 3 and 4 occur in 2035, Avista's strategy would change due to the 200 MW of Montana wind not being available because of limited transmission capacity. The plan would require nearly the same amount of pumped hydro as Portfolio #1 and would require 92 MW of natural gas-fired CTs. This scenario requires fewer renewable resources since it does not include CETA. This portfolio helps illustrate the change in portfolio cost with and without Colstrip due to Washington's CETA. This portfolio also provides details comparing a 2025 versus a 2035 Colstrip exit.

Table 12.7: Least Cost Plan with Colstrip extended to 2035, without CETA

Resource Type	Year	Capability (MW)
Montana wind	2022	100
Kettle Falls upgrade	2026	12
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	200
Lancaster PPA expires	2026	-257
Post Falls upgrade	2027	8
Natural Gas CT	2027	92
Mid-Columbia hydro	2031	75
Colstrip 3 & 4 exits portfolio	2035	-222
Northeast CTs retires	2035	-55
Natural Gas CT	2035	84
Liquid-air storage (16 hours)	2038-42	100
Lithium-ion storage (4 hours)	2039	25
Natural gas CT	2043	55
Lithium-ion storage (4 hour)	2045	53
Supply-side resource net total (MW)		294
Supply-side additions through 2045 (MW)		828
Demand Response through 2045 (MW)		88
Energy Efficiency through 2045 (aMW)		166

Portfolio #8: Least Cost Plan with Colstrip extended to 2035, with CETA

Portfolio #8 includes CETA assumptions, but moves Colstrip's proposed shutdown date to 2035. This portfolio helps identify whether or not Colstrip is cost effective to continue operating on a system basis to serve load outside of Washington. Portfolio #8 requires additional pumped hydro storage, selects no natural gas-fired CTs, and Montana wind shifts out until after Colstrip exits the portfolio in 2035.

Table 12.8: Least Cost Plan with Colstrip extended to 2035, with CETA

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2022	100
NW wind	2023	100
Kettle Falls upgrade	2024	12
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	250
Lancaster PPA expires	2026	-257
Post Falls upgrade	2027	8
Mid-Columbia hydro	2031	75
Northeast CTs retires	2035	-55
Long Lake 2nd powerhouse	2035	68
Colstrip 3 & 4 exits portfolio	2036	-222
MT wind	2036	200
Wind (including PPA renewals)	2042-2045	300
Liquid-air storage (16 hours)	2043	25
Solar w/ storage	2044	50
Storage for solar (4 hours)	2044	50
Lithium-ion storage (4 hour)	2045	175
Supply-side resource net total (MW)		1,003
Supply-side additions through 2045 (MW)		1,537
Demand Response through 2045 (MW)		112
Energy Efficiency through 2045 (aMW)		182

Portfolio #9: Least Cost Plan with 30 percent Higher Pumped Hydro Storage Costs

One of the risks of the PRS is the estimated costs of the long duration pumped hydro storage could be significantly higher than estimates used in the PRS. This portfolio's objective is to identify the breaking point. At 30 percent higher PPA costs, the model begins to shift pumped hydro to natural gas-fired CTs. Table 12.9 identifies these changes along with others.

Table 12.9: Least Cost Plan with 30 Percent Higher Pumped Hydro Storage Costs

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2022	100
NW wind	2023	100
Kettle Falls upgrade	2024	12
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	75
Colstrip 3 & 4 exits portfolio	2026	-222
Lancaster PPA expires	2026	-257
Natural gas CT	2027	92
Post Falls upgrade	2027	8
MT Wind	2027	200
Mid-Columbia hydro	2031	75
Northeast CTs retires	2035	-55
Long Lake 2nd powerhouse	2035	68
Liquid-air storage (16 hours)	2036-41	100
Wind (including PPA renewals)	2042-2045	300
Lithium-ion storage (4 hour)	2042-2045	303
Solar w/ storage	2044	50
Storage for solar (4 hours)	2044	50
Supply-side resource net total (MW)		1,123
Supply-side additions through 2045 (MW)		1,657
Demand Response through 2045 (MW)		111
Energy Efficiency through 2045 (aMW)		189

Portfolio #10: Least Cost Plan with Federal Tax Credit Extension

One of the challenges with high renewable penetration rates is the added costs of renewables above market prices. There are scenarios where the Federal government could extend the Wind PTC and Solar ITC. This portfolio identifies the changes in resource selection and changes in cost of this scenario. This scenario also identifies how avoided costs would change with a tax credit extension.

Table 12.10: Least Cost Plan with Federal Tax Credits Extension

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2023	200
Kettle Falls upgrade	2024	12
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	175
Colstrip 3 & 4 exits portfolio	2026	-222
Lancaster PPA expires	2026	-257
Post Falls upgrade	2027	8
MT Wind	2026	200
Mid-Columbia hydro	2031	75
Northeast CTs retires	2035	-55
Natural gas CT	2035	92
Liquid-air storage (16 hours)	2038-2043	100
Wind (including PPA renewals)	2042-2045	300
Lithium-ion storage (4 hour)	2043-2045	100
Solar w/ storage	2044-2045	150
Storage for solar (4 hours)	2044-2045	150
Supply-side resource net total (MW)		1,152
Supply-side additions through 2045 (MW)		1,686
Demand Response through 2045 (MW)		108
Energy Efficiency through 2045 (aMW)		181

Portfolio #11: Clean Resource Plan with Federal Tax Credits Extension

This scenario is similar to Portfolio #10, but this case meets Avista's Clean Energy Strategy's (similar to Portfolio #2) added renewable objective. This allows the addition of new resources at a lower cost with the tax credit while identifying cost increases necessary to move toward 100 percent clean energy when compared to the least cost strategy. This portfolio requires additional solar and storage resources toward the end of the plan.

Table 12.11: Least Cost Plan with Federal Tax Credits Extension

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW solar	2022	150
NW wind	2023	200
Kettle Falls upgrade	2024	12
Colstrip 3 & 4 exits portfolio	2026	-222
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	125
Lancaster PPA expires	2026	-257
Montana wind	2026	200
Post Falls upgrade	2027	8
NW Solar	2027-2031	350
Geothermal	2029	20
Mid-Columbia hydro	2031	75
Long Lake 2nd powerhouse	2031	68
Northeast CTs retires	2035	-55
Solar w/ storage	2033-2040	225
Storage for solar (4 hours)	2033-2040	225
Wind (including PPA renewals)	2041-2043	300
Lithium-ion storage (4 hours)	2042-2045	225
Liquid-air storage (16 hours)	2043	25
Solar w/ storage	2044-2045	75
Storage for solar (4 hours)	2044-2045	75
Supply-side resource net total (MW)		1,948
Supply-side additions through 2045 (MW)		2,482
Demand Response through 2045 (MW)		111
Energy Efficiency through 2045 (aMW)		203

Portfolio #12: Least Cost Plan with Low Economic Growth

Lower economic growth in the service territory may lead to flat load growth for Avista. This scenario estimates average energy will be approximately 89 aMW less than the PRS by 2045 and winter peak loads will be 136 MW less by 2045. Effectively, loads will be flat across the 25-year forecast in this scenario. Additional information regarding these low and high economic growth scenarios is included in Chapter 3. These load changes result in less generation required to meet load. Another item to note in this scenario is with lower growth, the amount of energy efficiency is likely to be overstated. Avista did not modify the Energy Efficiency potential study or ramp rates for this scenario.

Table 12.12: Low Economic Growth

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2022	100
Kettle Falls upgrade	2024	12
Colstrip 3 & 4 exits portfolio	2026	-222
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	100
Lancaster PPA expires	2026	-257
Montana wind	2027	200
Post Falls upgrade	2027	8
Mid-Columbia hydro	2031	75
Long Lake 2nd powerhouse	2031	68
Northeast CTs retires	2035	-55
Wind (including PPA renewals)	2042-2045	300
Lithium-ion storage (4 hours)	2041-2045	225
NW solar	2045	10
Supply-side resource net total (MW)		688
Supply-side additions through 2045 (MW)		1,222
Demand Response through 2045 (MW)		108
Energy Efficiency through 2045 (aMW)		180

Portfolio #13: Least Cost Plan with High Economic Growth

Higher economic growth in the service territory leads to higher load growth for Avista. This scenario estimates average energy will be approximately 96 aMW more than the PRS by 2045 and winter peak loads will be 152 MW higher by 2045. Additional information regarding this load scenario is included in Chapter 3. These load changes result in more generation required to meet load. Another item to note in this scenario is with higher growth, the amount of energy efficiency is likely to be understated. Avista did not modify the Energy Efficiency potential study or ramp rates for this scenario.

Table 12.13: High Economic Growth

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2022	100
NW wind	2023	100
Kettle Falls upgrade	2024	12
Colstrip 3 & 4 exits portfolio	2026	-222
Rathdrum CT 1 & 2 upgrades	2026	24
Long-duration pumped hydro	2026	250
Lancaster PPA expires	2026	-257
Montana wind	2027	200
Post Falls upgrade	2027	8
Mid-Columbia hydro	2031	75
Natural gas CT	2033	48
Long Lake 2nd powerhouse	2035	68
Northeast CTs retires	2035	-55
Natural gas CT	2037	48
Liquid air storage (16 hours)	2040-2043	100
Wind (including PPA renewals)	2041-2043	300
Solar w/ storage	2041-2045	205
Storage for solar (4 hours)	2041-2045	200
Lithium-ion storage (4 hours)	2043-2044	200
Geothermal	2045	20
Supply-side resource net total (MW)		1,524
Supply-side additions through 2045 (MW)		2,058
Demand Response through 2045 (MW)		112
Energy Efficiency through 2045 (aMW)		181

Portfolio #14: Least Cost Plan with Lancaster Extended Five Years

The Lancaster PPA expires in October 2026. The plant has not reached the end of its useful life and theoretically, the plant owner and Avista could agree to a PPA extension or another alternative such as a purchase and sale agreement. This scenario studies how the Avista portfolio may change with a five-year extension. Avista's interpretation of CETA would allow this extension since the plant currently meets the Washington emission performance standard and does not preclude Avista from meeting either of the clean energy objectives. The results of this portfolio removes the need of the long duration pumped hydro storage project but replaces it with a new natural gas-fired CT after the PPA ends in 2031. Acquiring Lancaster would be an alternative to construction of a new CT. Alternatively, if the pumped hydro was available at a lower price, it could be an alternative. Because there is no capacity shortfall in 2027, the need for Montana wind is delayed until the Northeast CT is retired and no Long Lake second power house is required, and is exchanged for additional solar and geothermal toward the end of the plan. Portfolio #14 financial results are not included in many of the following tables. The results may give counterparties specific information negating the benefits of potential RFP bidding. Appendix J is confidential to include these estimates.

Table 12.14: Least Cost Plan with Lancaster Extended Five Years

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2022	100
NW wind	2023	100
Kettle Falls upgrade	2024	12
Colstrip 3 & 4 exits portfolio	2026	-222
Rathdrum CT 1 & 2 upgrades	2026	24
Post Falls upgrade	2027	8
Mid-Columbia hydro	2031	75
Lancaster PPA expires	2032	-257
Natural gas CT	2032	245
Northeast CTs retires	2035	-55
MT wind	2035	200
Liquid air storage (16 hours)	2038-2043	100
Wind (including PPA renewals)	2041-2043	300
Lithium-ion storage (4 hours)	2042-2044	150
Solar w/ storage	2045	100
Storage for solar (4 hours)	2045	100
Geothermal	2045	20
Supply-side resource net total (MW)		1,100
Supply-side additions through 2045 (MW)		1,634
Demand Response through 2045 (MW)		108
Energy Efficiency through 2045 (aMW)		177

Portfolio #15: Least Cost Plan with Colstrip Unit #4 Extended to 2035

Avista does not have unilateral control of Colstrip's eventual shutdown date regardless of Avista's preference because of the ownership agreement. One potential outcome is for one unit to shut down while the other unit remains in service. This scenario attempts to show the changes in the portfolio mix and cost if this outcome occurs. With one unit of Colstrip shut down in 2025 and the other continuing until 2035, the major impacts are a shift in Montana wind to match transmission availability and the selection of a modest amount of additional long duration pumped hydro storage.

Table 12.15: Least Cost Plan with Colstrip 4 Extended to 2035

Resource Type	Year	Capability (MW)
Montana wind	2022	100
NW wind	2022	100
NW wind	2023	100
Kettle Falls upgrade	2024	12
Colstrip 3 exits portfolio	2026	-111
Rathdrum CT 1 & 2 upgrades	2026	24
Long duration pumped hydro	2026	225
Lancaster PPA expires	2027	-257
MT Wind	2027	100
Post Falls upgrade	2027	8
Mid-Columbia hydro	2031-2032	75
Long Lake 2nd powerhouse	2035	68
Northeast CTs retires	2035	-55
Colstrip 4 exits portfolio	2035	-111
MT wind	2037	100
Liquid air storage (16 hours)	2041-2043	75
Wind (including PPA renewals)	2042-2045	300
Lithium-ion storage (4 hours)	2044-2045	175
Solar w/ storage	2043-2044	55
Storage for solar (4 hours)	2043-2044	50
Supply-side resource net total (MW)		1,033
Supply-side additions through 2045 (MW)		1,567
Demand Response through 2045 (MW)		108
Energy Efficiency through 2045 (aMW)		182

Portfolio Summary Analysis

Avista studied 15 possible portfolios, each with possible levers that can change Avista's decision-making process. To summarize each of these outcomes and identify common trends for resource decisions prior to 2040, Table 12.16 shows what is common between all the scenarios and identifies resources pursued in all cases. In this figure, cells with the mark of "X" indicate a selection. Wind and long duration pumped hydro storage are the only resources called out due to significant changes in results.

Table 12.16: Resource Selection Matrix

	PRS	#2	#3	#4	#5	#6	#7	#8	#9	#10	#11	#12	#13	#14	#15
NW Wind	200	0	200	0	200	200	0	200	200	200	200	100	200	200	200
MT Wind	100	100	100	0	100	100	100	100	100	100	100	100	100	100	100
Addional: Solar energy			X		X						X				
Kettle Falls upgrade	X	X	X		X	X	X	X	X	X	X	X	X	X	X
Rathdrum CT upgrade	X	X	X		X	X	X	X	X	X	X	X	X	X	X
Post Falls upgrade	X	X	X	X	X	X	X	X	X	X	X	X		X	X
Long duration pumped hydro (2026)	175	200	125	0	150	0	200	250	75	175	125	100	200	0	225
Larger natural gas CT (2026-2030)						X									
Smaller natural gas CT (2026-2030)		X					X		X						
Montana wind (2026-2027)	X		X		X				X	X	X	X	X		X
Montana wind delayed						X		X						X	X
Mid-Columbia hydro	X	X	X		X	X	X	X	X	X	X	X	X	X	X
Addional: Solar energy			X		X						X				
Addional: Solar energy w/ storage					X						X				
Addional: Geothermal					X						X				
Long Lake 2nd powerhouse	X		X		X			X	X		X	X	X		X
Natural gas CT (2032-37)										X			X	X	
Liquid Air storage prior to 2040	X				X	X	X		X					X	
Liquid Air delayed		X	X					X			X	X	X		X

Cost and Rate Comparison

Avista chose two different metrics to illustrate the cost differences among the portfolios. The first metric is total revenue requirement and the second is average customer rates. This is a simple rate calculation of total revenue requirement divided by retail sales. The full 25-year term along with intermediate time steps for each of the methodologies is in Table 12.17. The table shows the results of the portfolios in tabular form including present value of revenue requirements (PVRR) for the first 10 years and 25 years and the effective rate for 2030 and 2045.

Table 12.17: Portfolio Costs and Rates

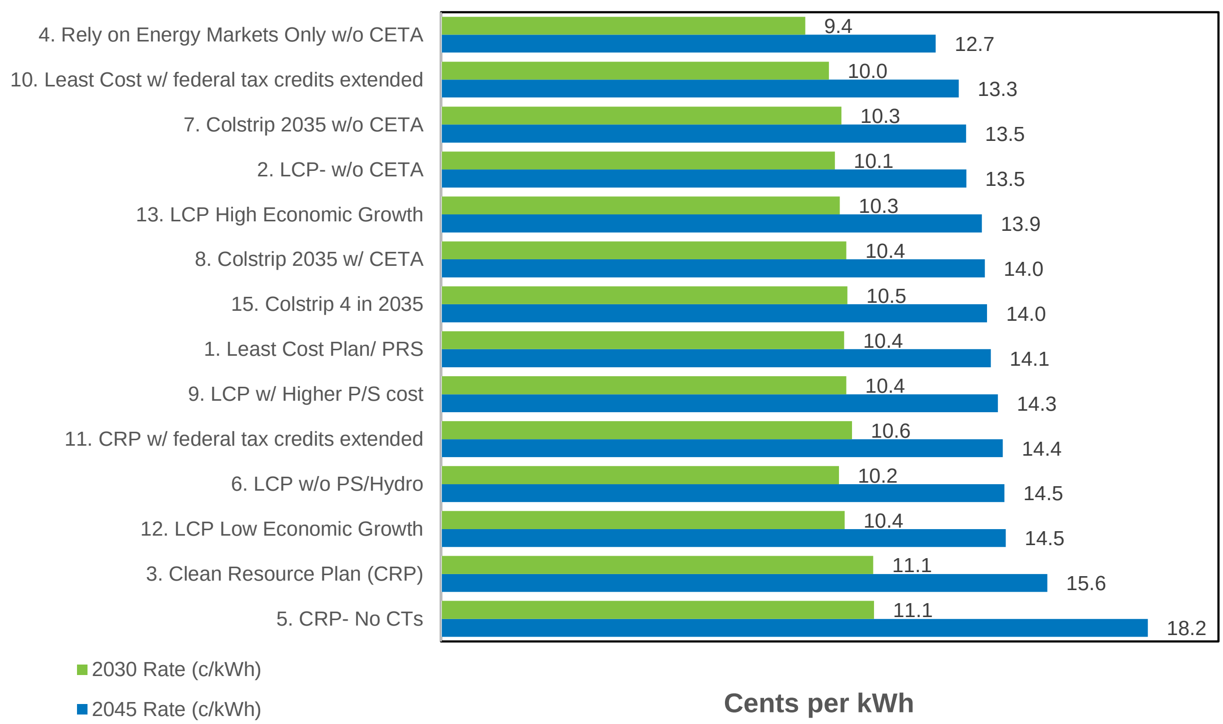
Portfolio Number	Portfolio name	PVRR (2021-45) Millions	PVRR (2021-30) Millions	2030 Rate (c/kWh)	2045 Rate (c/kWh)
1	Preferred Resource Strategy	11,832	6,329	10.4	14.1
2	Least Cost Plan- w/o CETA	11,670	6,222	10.1	13.5
3	Clean Resource Plan - 100% net clean by 2027	12,439	6,505	11.1	15.6
4	Rely on energy markets only (no capacity or renewable additions)	11,185	6,000	9.4	12.7
5	Clean Resource Plan - 100% net clean by 2027 and no CTs by 2045	12,563	6,511	11.1	18.2
6	Least Cost Plan w/o pumped hydro or Long Lake upgrade	11,826	6,270	10.2	14.5
7	Colstrip extended to 2035 w/o CETA	11,740	6,252	10.3	13.5
8	Colstrip extended to 2035 w/ CETA	11,852	6,346	10.4	14.0
9	Least Cost Plan w/ higher pumped hydro costs (+35%)	11,873	6,329	10.4	14.3
10	Least Cost Plan w/ federal tax credits extended	11,510	6,210	10.0	13.3
11	Clean Resource Plan w/ federal tax credits extended	12,004	6,344	10.6	14.4
12	Least Cost Plan w/ low economic growth	11,521	6,216	10.4	14.5
13	Least Cost Plan w/ high economic growth	12,106	6,391	10.3	13.9
15	Colstrip 4 extended to 2035	11,855	6,343	10.5	14.0

The lowest overall cost and the lowest energy rate portfolios are different due to the inclusion of net energy sales in the rate calculation. Portfolios with less energy sales may have higher rates due to fewer kWh to spread total costs over. Figure 12.3 shows the energy rates by portfolio sorted from lowest to highest. The lowest rate portfolios include scenarios without CETA or federal tax credit extensions. High economic growth also has lower rates as more energy is available to spread out all costs over.

Scenarios with Colstrip extending to 2035 (#7 and #8) have the same rate in 2030 as the PRS (#1) but slightly lower energy rates in 2045. Although the total cost is higher by $2 million each year to keep Colstrip in the portfolio through 2035 as shown in Figure 12.4. Even if CETA was not in place, the total cost is higher to keep Colstrip through 2035 is higher as shown in the change in cost between portfolio #7 and portfolio #2.

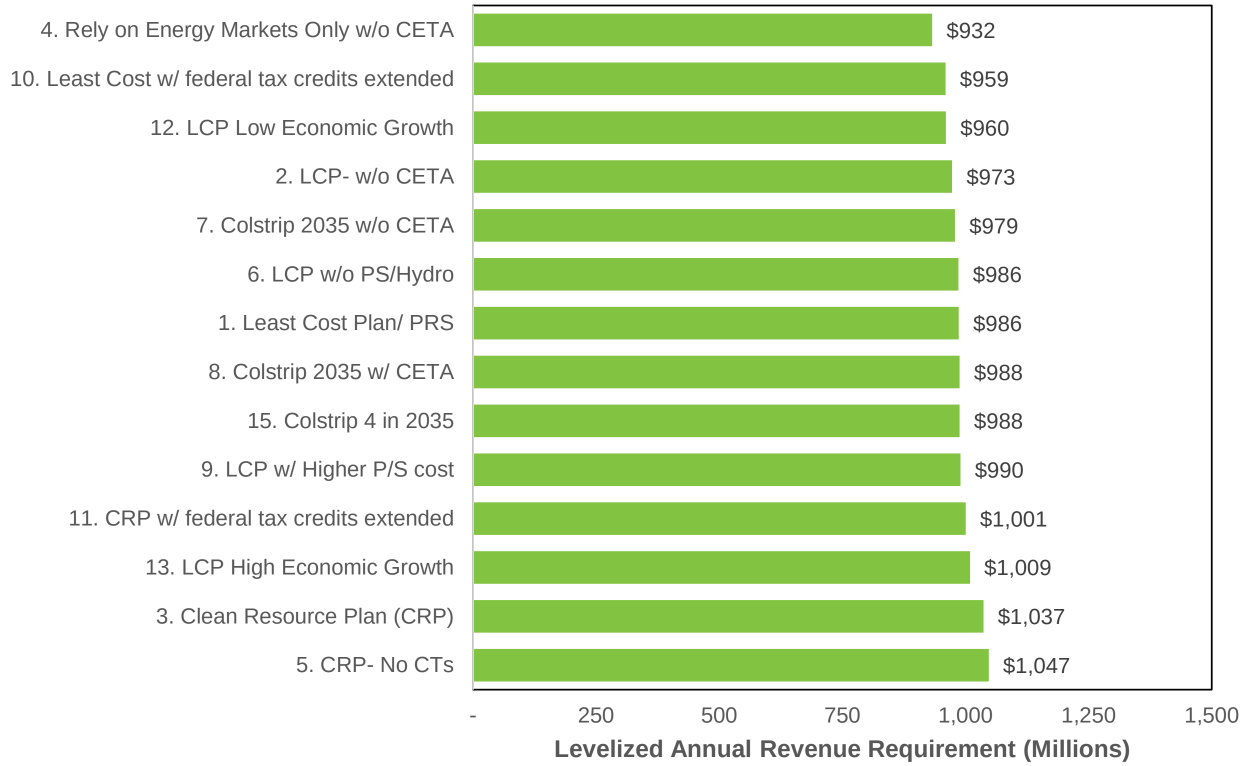
The PRS is also lower cost compared to the portfolio with only Colstrip Unit 4 being operational until 2035. The differences in order of portfolio rates and revenue requirement costs come down to energy efficiency. Both portfolios use the same load forecast, but if Colstrip exits beyond 2025, it will create the need for more energy efficiency, thereby reducing energy sales and creating higher rates.

Figure 12.3: Portfolio Average Energy Rates



One advantage of showing both the 2030 and 2045 rates, as opposed to solely analyzing the costs, is the ability to compare rate outcomes toward the end of the plan. In this example, adding more clean energy and retiring natural gas-fired plants shows a separation in rates from the other scenarios.

Figure 12.4: Portfolio Average Energy Levelized Revenue Requirement



Greenhouse Gas Analysis

The portfolios studied in the chapter all are consistent with a net reduction of greenhouse gas emissions, but the reduction timing and levels differ. Avista explored two methods to analyze greenhouse gas emissions. Figure 12.5 shows the annual emissions in millions of metric tons for each of the scenarios by year. Portfolios with Colstrip extending its operation beyond 2025 show higher emissions. Clean energy extensive portfolios reduce emissions to around 250,000 metric tons each year. Portfolios with no CT's, such as Portfolio #5, still have some greenhouse gas emissions due to market transactions.

The second method of reviewing the data levelizes the 25-year emissions using the 2.5 percent discount rate identified under CETA and Avista's 6.68 percent discount rate. This levelization shows the overall emissions of the portfolios. As expected, portfolios with higher levels of renewables have lower net emissions as compared to other portfolios. Figure 12.5 ranks the portfolios by emissions levels.

A chart to compare both greenhouse gas emissions and costs for each portfolio is helpful to understand each portfolio's carbon efficiency. To further this concept, Figure 12.7 compares each portfolio's change in levelized cost and levelized emissions from Portfolio #2. Where Portfolio #2 is a base portfolio without specific greenhouse reduction goals. The portfolios with increasing cost for fewer emissions are in the top left quadrant. Effectively, these portfolios develop a cost per ton of emissions reduction. For example, the Avista PRS adds $44 per metric ton for emission reduction. The Clean Resource Plan

(CRP) (#3) has a higher ratio of $144 per metric ton and CRP without CTs (#5) $166 per metric ton on average for the 25 years. Portfolios with increasing costs and increasing emissions are in the top right quadrant. These portfolios are where Colstrip operates longer. The lower right quadrant of higher emissions and lower cost is rare and only occurs with no resource additions in Portfolio #4. The bottom left quadrant of lower cost and lower emissions is the best-case scenario, but this only results with lower loads due to low economic growth or federal tax credit extensions.

Figure 12.5: Portfolio Annual Greenhouse Gas Emissions

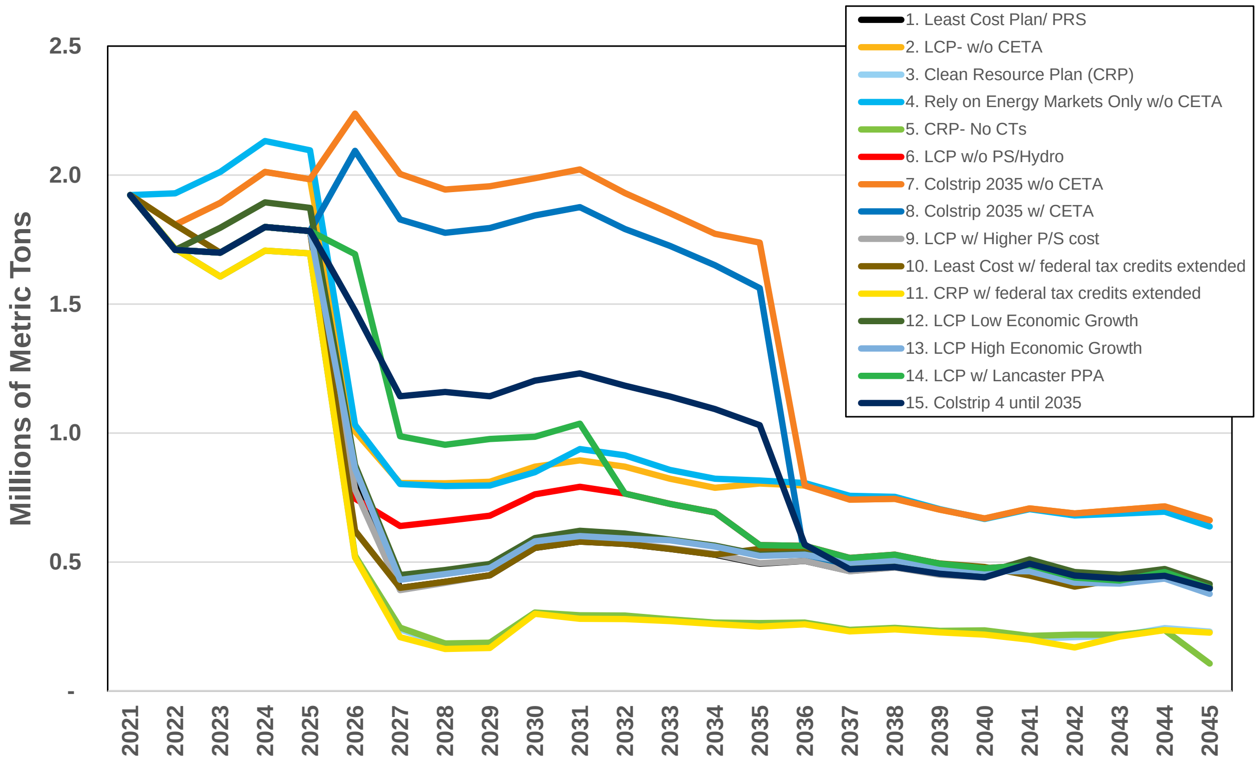


Figure 12.6: Levelized Greenhouse Gas Emissions

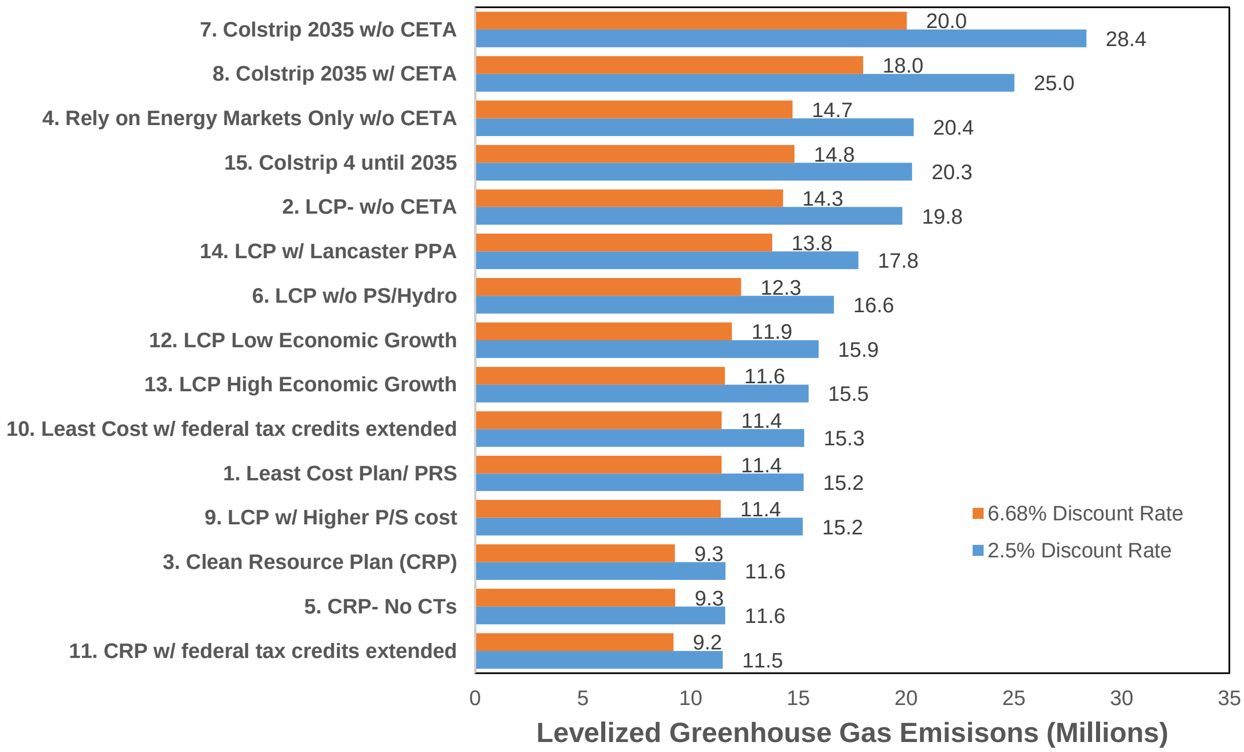
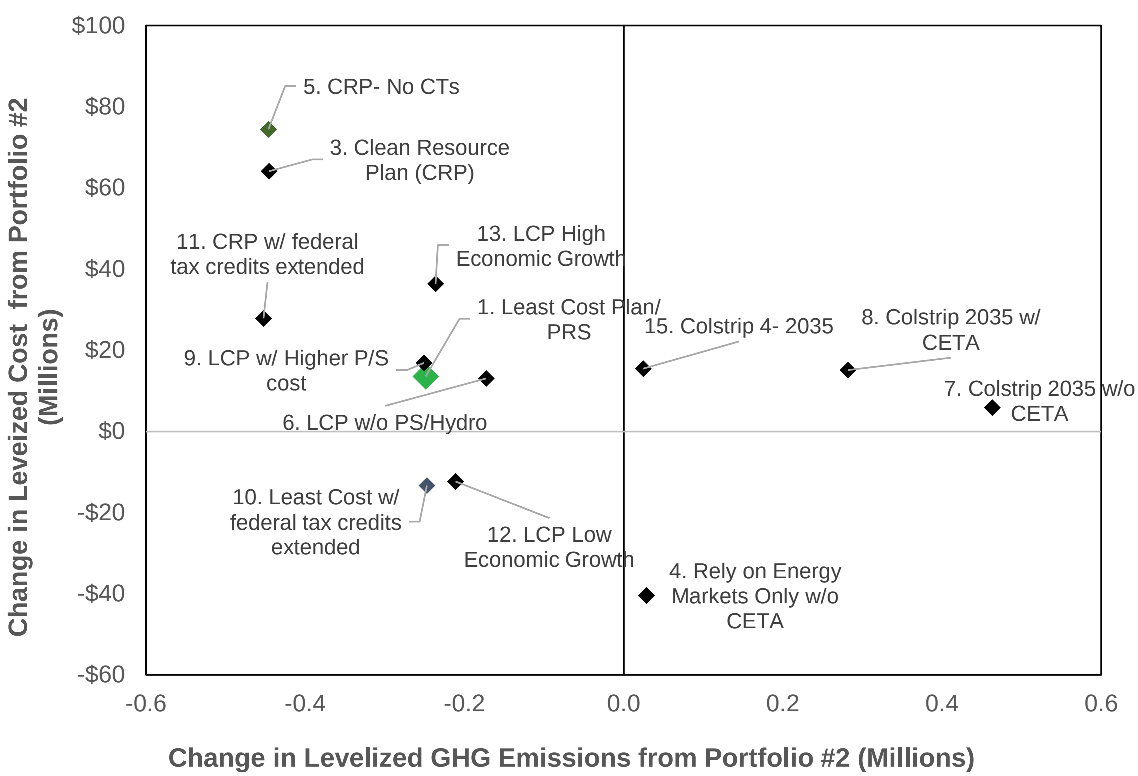


Figure 12.7: Change in Greenhouse Gas Emissions Compared to Change in Cost

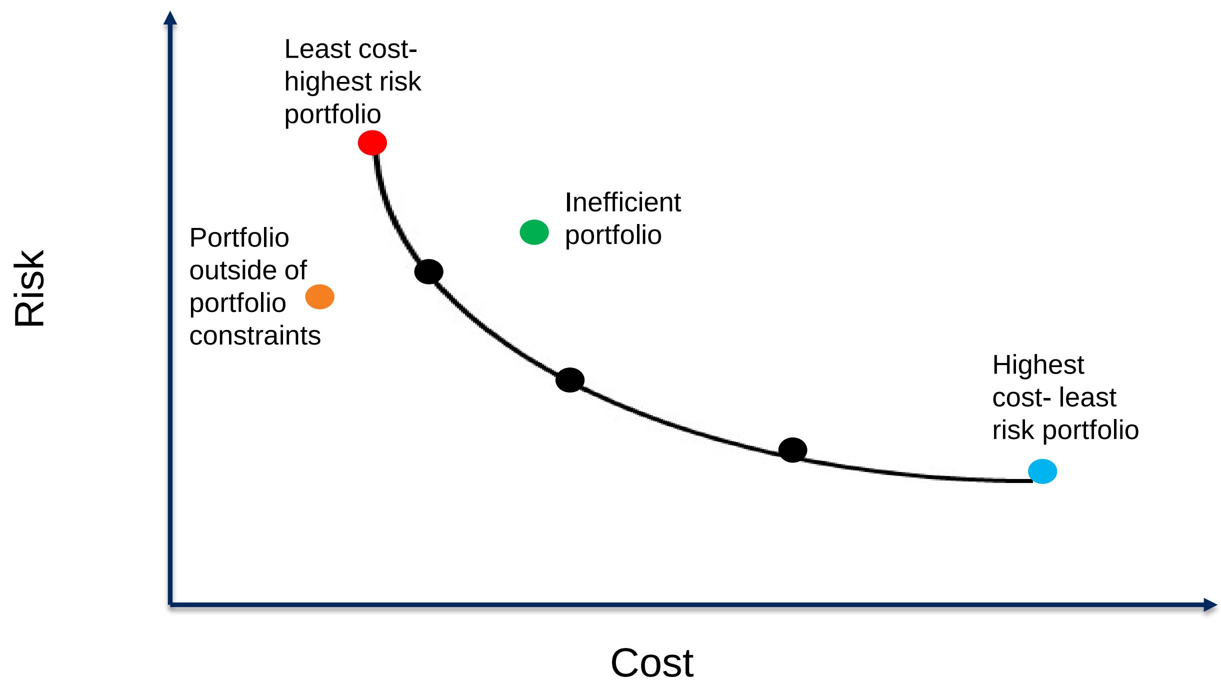


Risk Analysis

Avista's 500 simulations of market prices allow Avista to study the portfolio cost in different market conditions and allow the potential to create portfolios that lower risk for customers. Portfolio costs can include the standard deviation of cost and tail risk to measure each portfolio's risk.

Avista typically shows its cost versus risk metrics graphically with cost on the x-axis and risk on the y-axis. This method shows the tradeoff between cost and risk. Avista also developed portfolios to compare to the least cost portfolio by creating an efficient frontier of portfolios (see Figure 12.8). This method shows the lowest cost portfolios for each level of risk. This is helpful in showing the differences in handpicked resource strategies risk compared to a more optimal portfolio development.

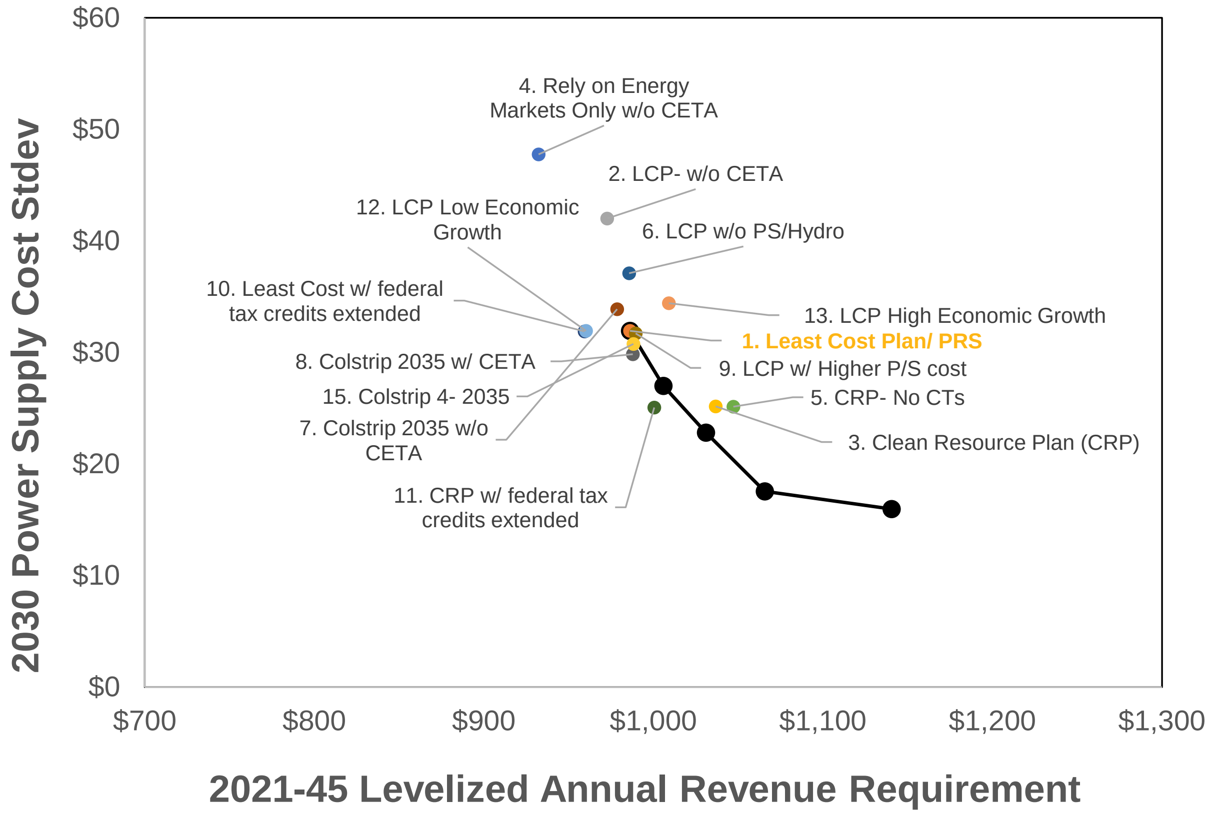
Figure 12.8: Conceptual Efficient Frontier Curve



Costs increase as you attempt to lower risk of portfolios. The optimal point on the Efficient Frontier depends on the level of acceptable risk. No best point on the curve exists, but Avista prefers points where small incremental cost additions offer larger risk reductions. Portfolios to the left of the curve are more desirable but do not meet the planning requirements or resource constraints. Examples of these constraints include environmental costs, regulation, and the availability of commercially viable technologies. Portfolios to the right of the curve are less efficient as they have higher costs than a portfolio with the same level of risk. PRiSM meets all deficit projections with new resources of the actual sizes available in the marketplace and does not rely on market purchases.

Figure 12.9 shows the mapping of the levelized portfolio cost and 2030 risk. The black line represents the portfolios along the Efficient Frontier; including the PRS, which is the lowest cost and highest risk portfolio. There are portfolios to the left of the Efficient Frontier, these portfolios are scenario where cost are lower either due to less regulation or where tax credits are available. There are portfolios to the right of the Efficient Frontier as well that may be an efficient method to reduce risk, but they may not meet other objectives such as greenhouse gas emissions reductions. The portfolios with higher risk typically have less resource additions such as Portfolio #4 and Portfolio #2.

Figure 12.9: Portfolios Compared to the Efficient Frontier

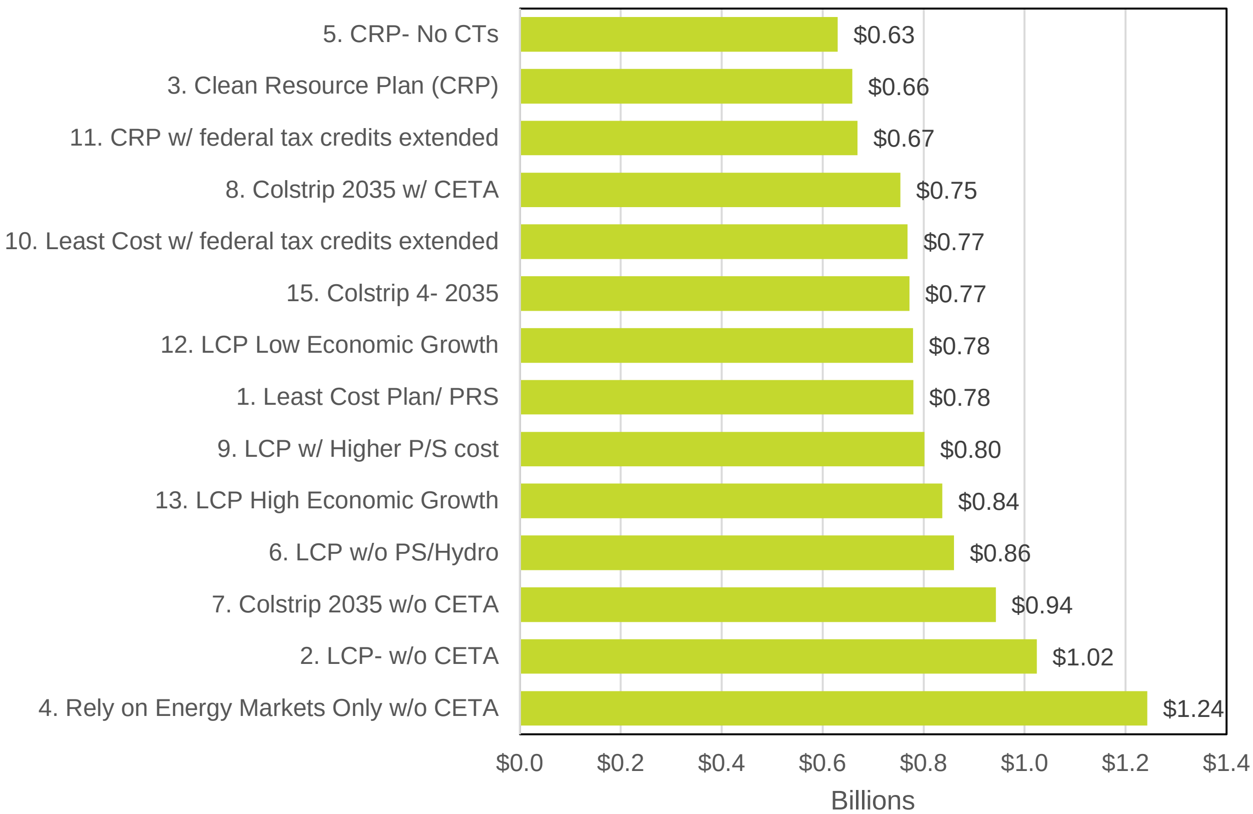


Avista selected two other risk measurements besides standard deviation from the Efficient Frontier analysis. The second metric is tail risk; in this case, it is the 95th percentile of costs minus the mean cost or TailVar95. Figure 12.9 shows this example with portfolios sorted from lowest risk to highest risk. The tail risk does not include the social cost of carbon (SCC).

The other risk metric is similar to TailVar95, but it includes the tail risk added to the expected costs. Figure 12.10 shows this methodology. The data includes examples both with and without the SCC. In Figure 12.11 the blue bars show the total present value of revenue requirement (PVRR) with risk at the 95th percentile without the SCC; the orange triangles include the same cost but with the SCC. The circle value and the yellow diamond is the cost plus one standard deviation with and without the SCC.

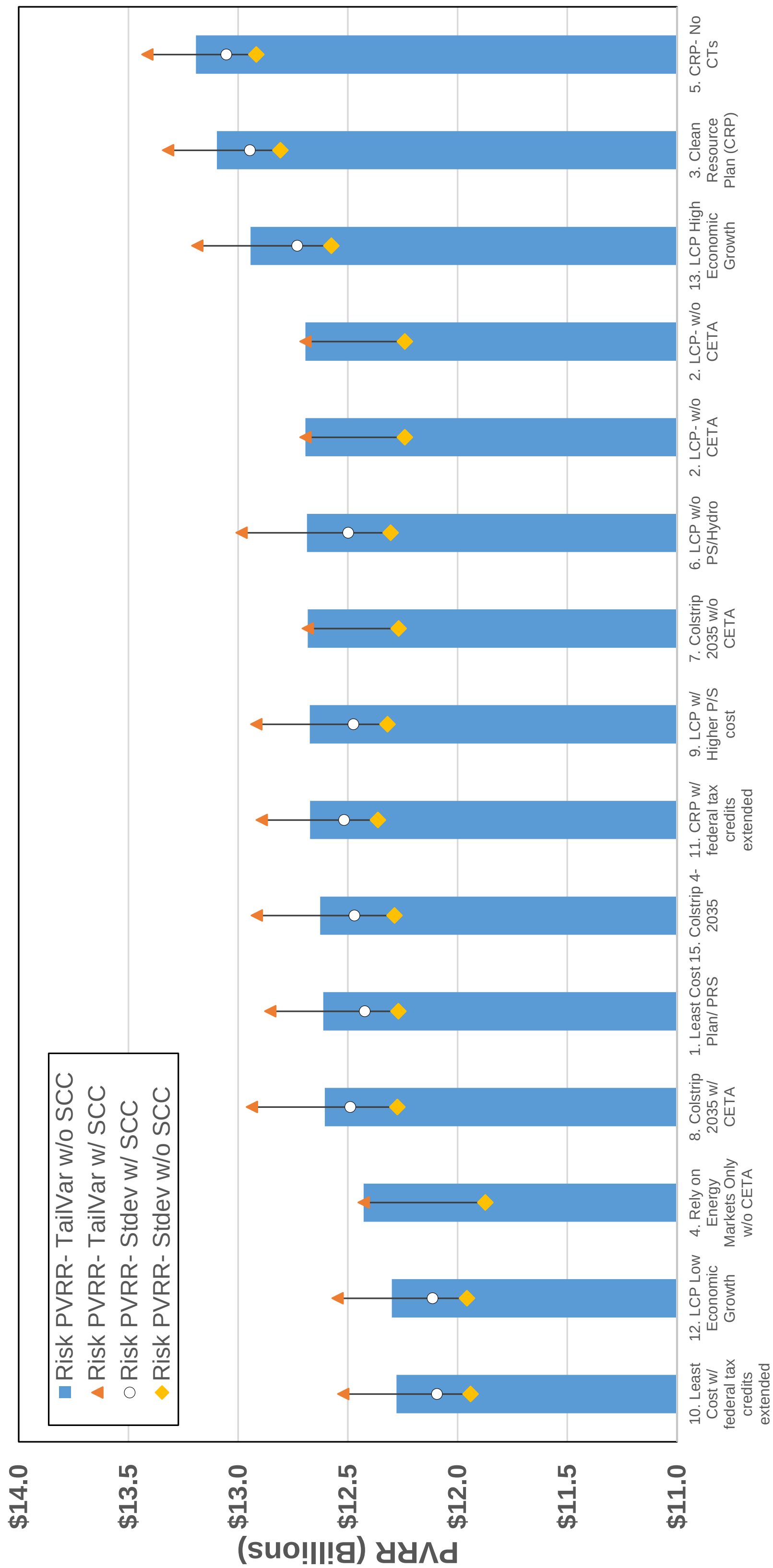
The TailVar95 analysis shows portfolios with higher penetrations of renewables have lower tail risk due to fixed pricing of the resources. Also there are lower market risks of portfolios with additional coal generation.

Figure 12.10: Portfolio TailVar95 Analysis



Taking into account total cost with risk, Figure 12.11 shows the lowest risk with cost is the portfolio with tax credits extended or lower loads. It is interesting that the Colstrip extended to 2035 Portfolio #8 has a slightly lower risk adjusted cost then this portfolio unless the SCC is included in the cost. The higher cost portfolios include higher loads, and heavy clean energy portfolios, even in cases considering the SCC.

Figure 12.11: Portfolio PVRR with Risk Analysis



Market Price Sensitivities

Another way to measure risk for each portfolio is to compare its cost under different specific market conditions rather than rely on the stochastic study. This section compares each portfolio using the electric price scenarios described in Chapter 10. The scenarios include a deterministic study of the Expected Case, while fixing the major risk variables such as hydroelectric and natural gas at expected averages. Scenario 2 assumes a future without CETA (to be able to calculate the cost of that law), Scenario 3 is low natural gas prices, Scenario 4 is high natural gas prices, and Scenario 5 is the SCC as a tax across the entire Western Interconnect.

The following tables show the change in cost and greenhouse emissions given these pricing sensitivities. Table 12.18 shows the cost changes compared to the Expected Case revenue requirements from the deterministic price forecast. In general, the “No CETA” scenario increases costs due to slightly higher market prices, increasing Avista’s cost to serve customers. The “Low NG Prices” scenario generally lowers cost and “High NG Prices” generally increases total costs. The final scenario of including the SCC as a tax increases costs in all portfolios.

Table 12.19 shows the cost change to the PRS for both the stochastic market forecast and the deterministic scenarios. The scenarios generally follow the same cost changes as the Expected Case with the exception of the SCC tax scenario where additional renewables stabilize the cost. Portfolios with less or more natural gas-fired resources have costs that follow changes in natural gas prices.

Table 12.20 shows greenhouse gas emissions changes compared to the deterministic Expected Case. The “No CETA” scenario generally increases emissions as less renewables are in the system and natural gas-fired generation is dispatching more aggressively. The lower natural gas price scenario also increases emissions, as it is cheaper to run natural gas-fired generation. Since Colstrip closes in 2025 (early in the study), the lower coal generation dispatch does not have a major impact on total emissions. Higher natural gas prices results in a mixture of results with both higher and lower emissions depending on the scenario. While the SCC tax scenario lowers emissions by large amounts.

Table 12.18: Change in Cost (PVRR) Compared to Expected Case

Portfolios	No CETA	Low NG Prices	High NG Prices	Social Cost of Carbon
1. Least Cost Plan/ PRS	0.6%	-3.0%	2.6%	10.5%
2. LCP- w/o CETA	0.8%	-4.4%	4.3%	15.5%
3. Clean Resource Plan (CRP)	0.1%	-2.3%	1.7%	7.6%
4. Rely on Energy Markets Only w/o CETA	0.4%	-5.8%	6.0%	19.5%
5. CRP- No CTs	0.2%	-2.0%	1.5%	7.6%
6. LCP w/o PS/Hydro	0.3%	-3.7%	3.5%	12.4%
7. Colstrip 2035 w/o CETA	0.7%	-3.8%	3.0%	14.8%
8. Colstrip 2035 w/ CETA	0.7%	-2.7%	2.2%	13.1%
9. LCP w/ Higher P/S cost	0.4%	-3.1%	2.8%	10.5%
10. Least Cost w/ federal tax credits extended	0.6%	-3.1%	2.7%	10.8%
11. CRP w/ federal tax credits extended	0.1%	-2.3%	1.8%	7.9%
12. LCP Low Economic Growth	0.4%	-3.0%	2.7%	11.3%
13. LCP High Economic Growth	0.8%	-3.2%	2.9%	10.9%
15. Colstrip Unit 4 through 2035	0.6%	-2.8%	2.4%	11.9%

Table 12.19: Change in Cost (PVRR) Compared to PRS

Portfolios	Expected Case (Stoch)	Expected Case (Det)	No CETA	Low NG Prices	High NG Prices	Social Cost of Carbon
2. LCP- w/o CETA	-1.4%	-1.8%	-1.6%	-3.3%	-0.1%	2.7%
3. Clean Resource Plan (CRP)	5.1%	5.3%	4.7%	6.0%	4.4%	2.5%
4. Rely on Energy Markets Only w/o CETA	-5.5%	-6.4%	-6.6%	-9.1%	-3.3%	1.2%
5. CRP- No CTs	6.2%	6.4%	5.9%	7.4%	5.2%	3.5%
6. LCP w/o PS/Hydro	-0.1%	0.0%	-0.3%	-0.8%	0.9%	1.8%
7. Colstrip 2035 w/o CETA	-0.8%	-1.0%	-1.0%	-1.9%	-0.6%	2.9%
8. Colstrip 2035 w/ CETA	0.2%	0.3%	0.4%	0.6%	-0.1%	2.7%
9. LCP w/ Higher P/S cost	0.3%	0.3%	0.1%	0.1%	0.4%	0.3%
10. Least Cost w/ federal tax credits extended	-2.7%	-2.7%	-2.7%	-2.8%	-2.6%	-2.4%
11. CRP w/ federal tax credits extended	1.4%	1.7%	1.1%	2.4%	0.8%	-0.7%
12. LCP Low Economic Growth	-2.6%	-2.8%	-3.1%	-2.9%	-2.7%	-2.2%
13. LCP High Economic Growth	2.3%	2.5%	2.6%	2.2%	2.8%	2.8%
15. Colstrip Unit 4 through 2035	0.2%	0.3%	0.3%	0.4%	0.1%	1.6%

Table 12.20: Levelized Greenhouse Gas Emissions vs. Expected Case

Portfolios	No CETA	Low NG Prices	High NG Prices	Social Cost of Carbon
1. Least Cost Plan/ PRS	3.0%	8.7%	-1.1%	-36.8%
2. LCP- w/o CETA	5.2%	8.2%	-0.8%	-32.4%
3. Clean Resource Plan (CRP)	1.6%	11.2%	-1.1%	-43.9%
4. Rely on Energy Markets Only w/o CETA	2.7%	3.7%	-3.6%	-29.3%
5. CRP- No CTs	2.6%	11.2%	0.3%	-43.3%
6. LCP w/o PS/Hydro	1.9%	8.2%	-4.6%	-36.0%
7. Colstrip 2035 w/o CETA	4.2%	1.8%	0.0%	-53.6%
8. Colstrip 2035 w/ CETA	3.9%	2.0%	0.8%	-57.2%
9. LCP w/ Higher P/S cost	1.7%	7.9%	-2.9%	-37.2%
10. Least Cost w/ federal tax credits extended	2.7%	2.7%	-1.5%	-37.1%
11. CRP w/ federal tax credits extended	1.9%	11.6%	-0.8%	-44.3%
12. LCP Low Economic Growth	1.8%	6.8%	-2.7%	-35.3%
13. LCP High Economic Growth	4.0%	10.2%	4.0%	-37.4%
14. LCP w/ Lancaster PPA	2.6%	7.5%	-4.5%	-38.3%
15. Colstrip Unit 4 through 2035	3.6%	4.5%	0.2%	-49.8%

Table 12.21: Change in Levelized Greenhouse Gas Emissions Compared to the PRS

Portfolios	Expected Case (Stoch)	Expected Case (Det)	No CETA	Low NG Prices	High NG Prices	Social Cost of Carbon
2. LCP- w/o CETA	30.0%	24.1%	26.8%	23.6%	24.4%	32.9%
3. Clean Resource Plan (CRP)	-23.8%	-20.4%	-21.5%	-18.6%	-20.5%	-29.3%
4. Rely on Energy Markets Only w/o CETA	33.5%	26.5%	26.2%	20.7%	23.3%	41.5%
5. CRP- No CTs	-23.9%	-20.7%	-21.0%	-18.9%	-19.6%	-28.8%
6. LCP w/o PS/Hydro	9.2%	8.0%	6.9%	7.5%	4.2%	9.3%
7. Colstrip 2035 w/o CETA	86.0%	88.2%	90.5%	76.3%	90.2%	38.2%
8. Colstrip 2035 w/ CETA	64.1%	71.3%	72.8%	60.7%	74.5%	15.9%
9. LCP w/ Higher P/S cost	-0.3%	-0.8%	-2.1%	-1.5%	-2.7%	-1.3%
10. Least Cost w/ federal tax credits extended	0.2%	-0.1%	-0.4%	-5.6%	-0.5%	-0.6%
11. CRP w/ federal tax credits extended	-24.6%	-21.1%	-21.9%	-19.0%	-20.9%	-30.4%
12. LCP Low Economic Growth	4.5%	2.7%	1.5%	1.0%	1.0%	5.1%
13. LCP High Economic Growth	1.5%	1.5%	2.5%	2.9%	6.7%	0.5%
14. LCP w/ Lancaster PPA	16.6%	15.7%	15.2%	14.4%	11.6%	12.9%
15. Colstrip Unit 4 through 2035	33.0%	36.2%	37.0%	31.0%	37.9%	8.3%

Electrification Scenario

Recently, there is a movement to develop policies supporting the electrification of energy to reduce greenhouse gas emissions. While there is potential to lower emissions with this strategy, there are serious consequences and considerations requiring analysis prior to pursuing the strategy. Specifically, analysis will be required to determine the costs to the power system and homeowners, but also if technology exists to reliably serve customers' new heating and transportation needs.

Avista considered three potential changes to the power system for this scenario. The first change is an increase in electric vehicles (EV), the second is an increase in rooftop solar systems, and the last is electrification of space and water heating systems away from the Local Distribution Company's (LDC) natural gas system. Avista modeled each of these potential load scenarios as possible changes of customer adoption over time. The descriptions of specific changes to the assumptions and load is below.

Electric Vehicles

The Expected Case (used in the PRS) includes a significant increase in EVs throughout the 25-year forecast; see Table 12.12 identified as the "High EV Penetration". In 2021, the study includes nearly 1,200 vehicles in the service territory increasing to over 100,000 in 2045. This assumes an 18.7 percent year-over-year increase, whereas the electrification scenario increases this trajectory to a 23 percent year-over-year increase for 250,000 EVs by 2045. This IRP estimates the greenhouse gas emissions reductions using the number of new EVs, new load and the average emissions rates per vehicle.

For the load estimate, additional kWh per vehicle increases over time to account for larger battery systems. Although, the winter peak increase per vehicle remains flat to simulate the effect of time of vehicle changing away from peak hours. Figure 12.13 shows the total change in energy and peak load. In 2030, the higher EV penetration increases energy load by only 1 aMW, but by 2045, when our higher EV penetration shows an exponential growth rate, energy load increases to 65 aMW and peak load increases by 107 MW.

The Expected Case assumes regional greenhouse gas emissions from petroleum for transportation fall by nearly 40,000 metric tons in 2030, growing to 530,000 metric tons by 2045. In the higher electrification scenario, petroleum emissions fall by 59,000 metric tons by 2030, and 1,300,000 metric tons by 2045. The emissions reductions from EVs would not reduce utility emissions, but they highlight the magnitude of the greenhouse gas emissions reductions for the region from the electrification of transportation.

Figure 12.12: Electrification Scenario: EV Forecast Comparison

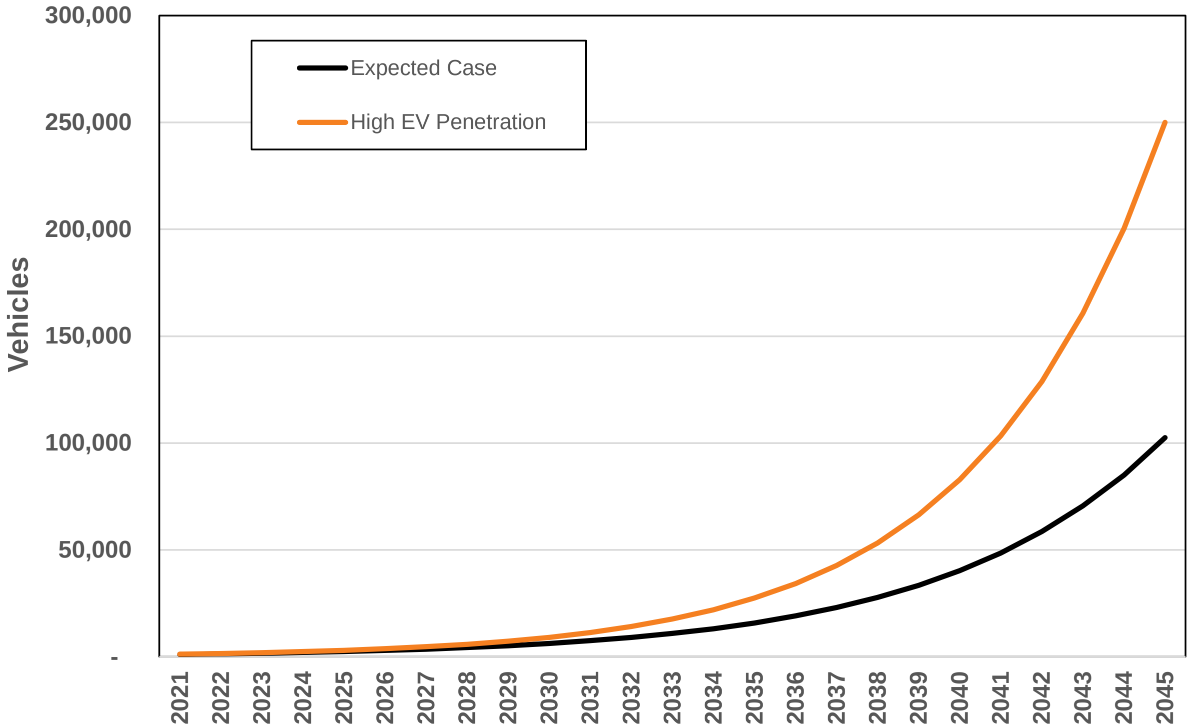
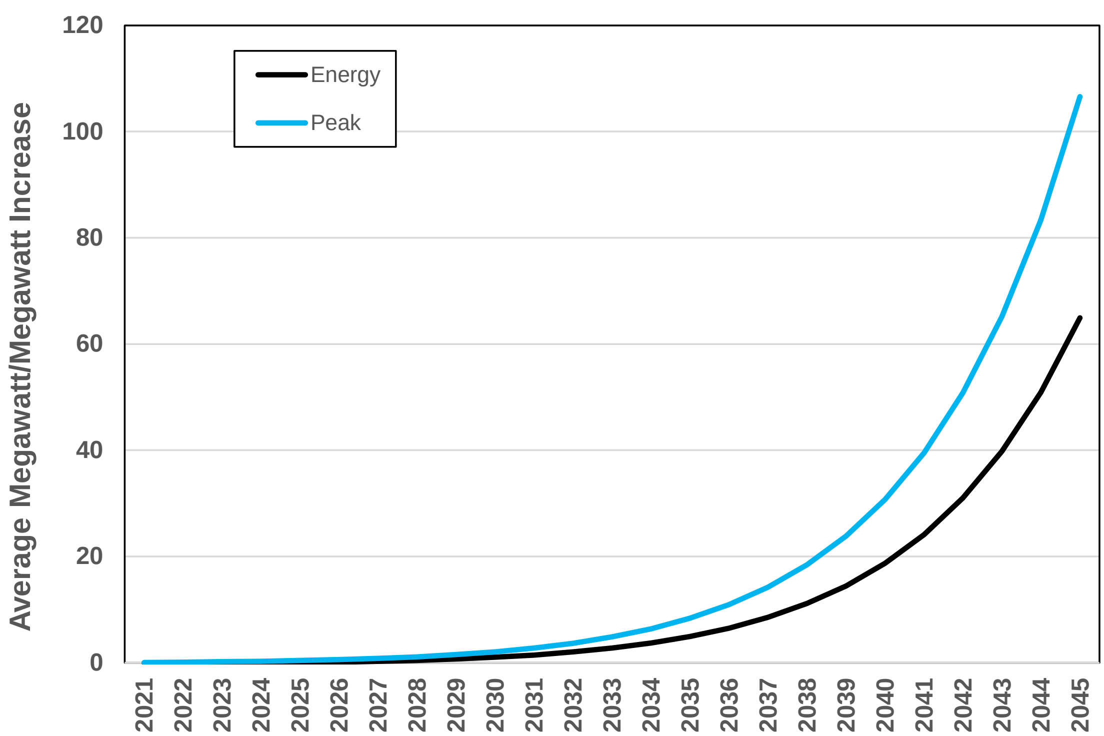


Figure 12.13: Electrification Scenario: EV Load Forecast Comparison



Rooftop Solar

The electrification scenario assumes additional rooftop solar penetration. The drivers for additional rooftop solar could be either economically driven by lower installation cost, higher utility cost, or even government subsidies. Regardless of the reason for the increase, understanding the effects to load is important to understand. The estimate of the load reduction includes assumptions on the number of solar systems, the size of the systems, and the efficiency of the systems. This scenario uses the Expected Case's load forecast for system size and efficiency, but the number of systems increases by changing the penetration rate of customers installing solar. The scenario assumes the penetration rate doubles by 2030; but by 2045, the penetration is 10 percent compared to 2.2 percent in the Expected Case. Figure 12.14 shows the rooftop solar customer count estimates for this scenario compared to the Expected Case. This scenario shows an exponential growth of rooftop solar compared to a linear growth in the Expected Case.

The change in load for solar is a simple calculation using system size and efficiency compared to the total number of systems. Figure 12.16 shows these total estimates. In this scenario, average load falls by an additional 2 aMW by 2030, but as the solar penetration growth intensifies by 2045, load is approximately 47 aMW lower, and nearly 100 aMW lower at summer peaks. Although, load falls in both annual energy and during the summer, Avista assumes no winter peak reduction due to timing of winter peak load occurring when it is dark. Future solar systems could have storage to shift some of the load to off peak periods. Although possible with residential storage, the net system effect would be small due to reliability periods of concern typically coinciding with low solar output and the relatively short term residential storage devices duration may not be long enough.

Figure 12.14: Electrification Scenario: Rooftop Solar Customer Count Comparison

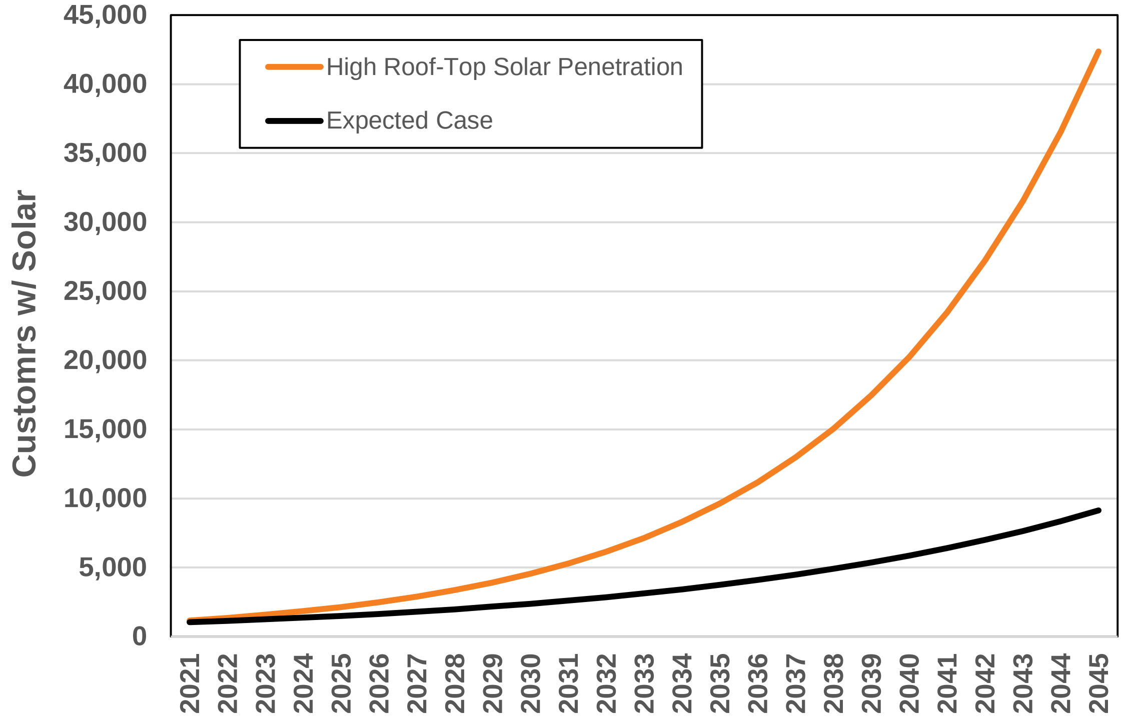
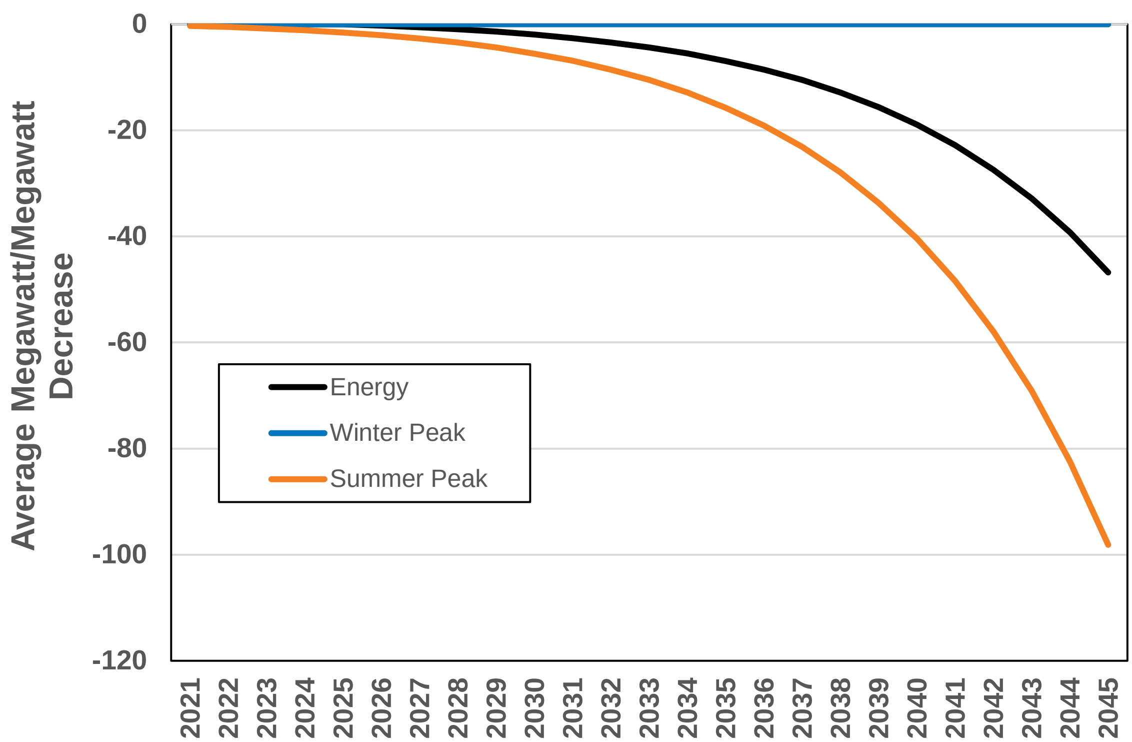


Figure 12.15: Electrification Scenario: Rooftop Solar Load Changes

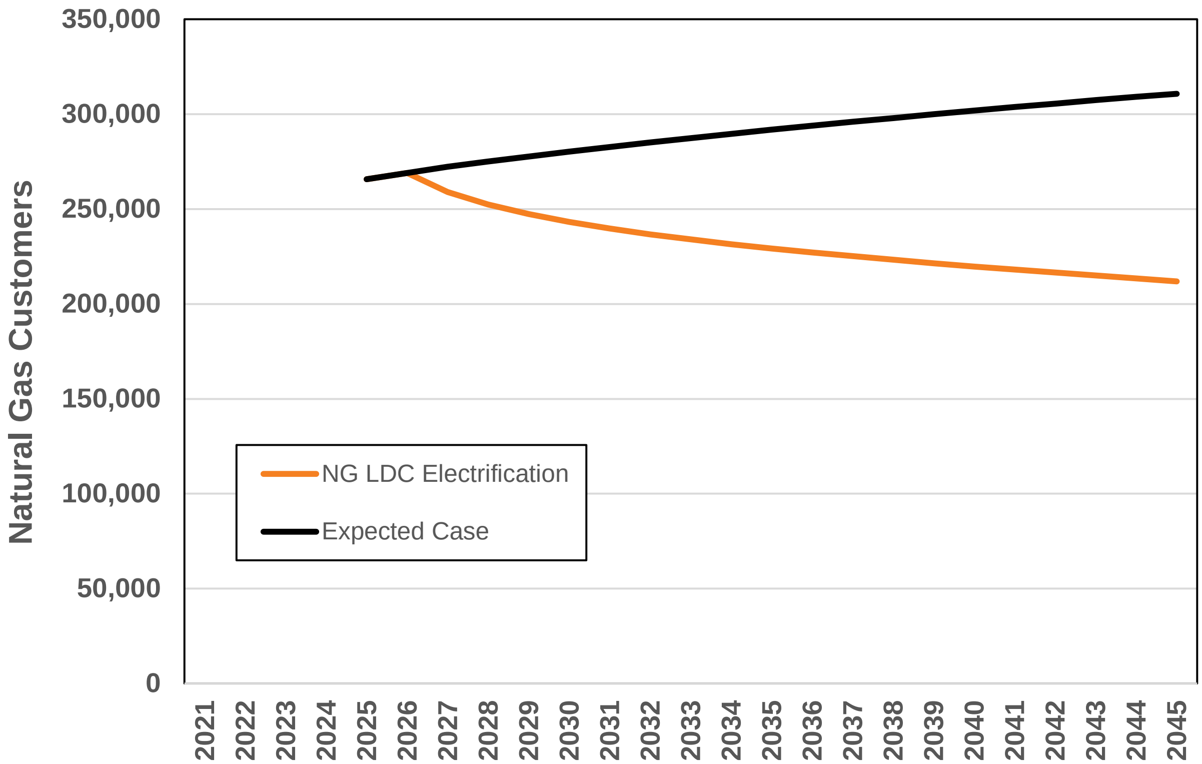


Space and Water Heating Electrification

The last component of the electrification scenario is to understand how load would change if customers switch from natural gas to electric for space and water heating. Avista has encouraged customers to switch to natural gas for benefits including comfort, convenience, and lower heating cost. Further, it is a more efficient method of delivering heat in cold periods compared to burning natural gas in a CT to make electricity and transmit it to customers. The downside to natural gas is the associated greenhouse gas emissions.

To estimate the impact to loads is a challenge specifically to peak loads. The load conversion estimate begins with an estimate of natural gas penetration rates from the Expected Case's load forecast. In this forecast, the 70 percent penetration rate assumption remains flat. Beginning in 2026, the penetration rate begins to decline until nearly 100,000 customers convert from natural gas to electric. This methodology simulates new homes constructed as all electric homes and existing homes slowly converting as older natural gas systems require replacement. The natural gas penetration rate included in the load forecast allows an estimate for the reduction in load from the number of customers on average; this estimate is approximately 15,000 additional kWh per electric customer annually.

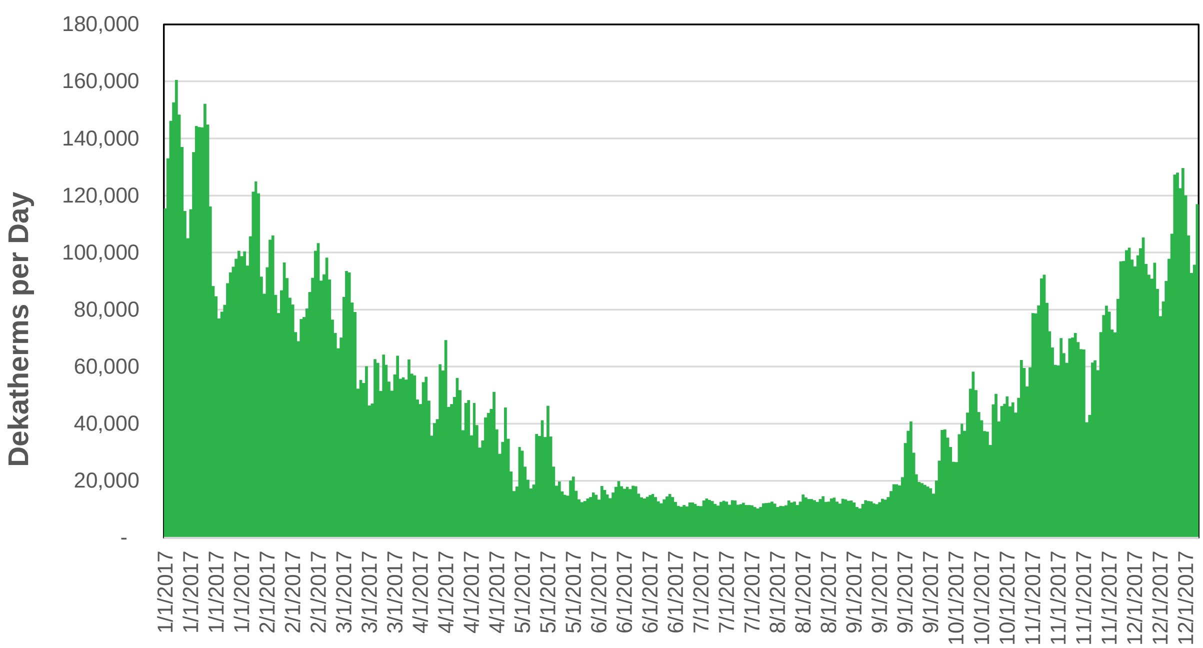
Figure 12.16: Electrification Scenario: Electric Customer's with Natural Gas



The larger challenge in the scenario is to understand how the load shape and peak loads will change with customers moving to electric space and water heating. Much of this estimate deals with efficiency of end use consumption of electricity and natural gas today. This begins with Figure 12.17, which shows the historical natural gas load from Avista's system (Washington and Idaho). Since the primary use of natural gas is for heating, the use is primarily in winter months.

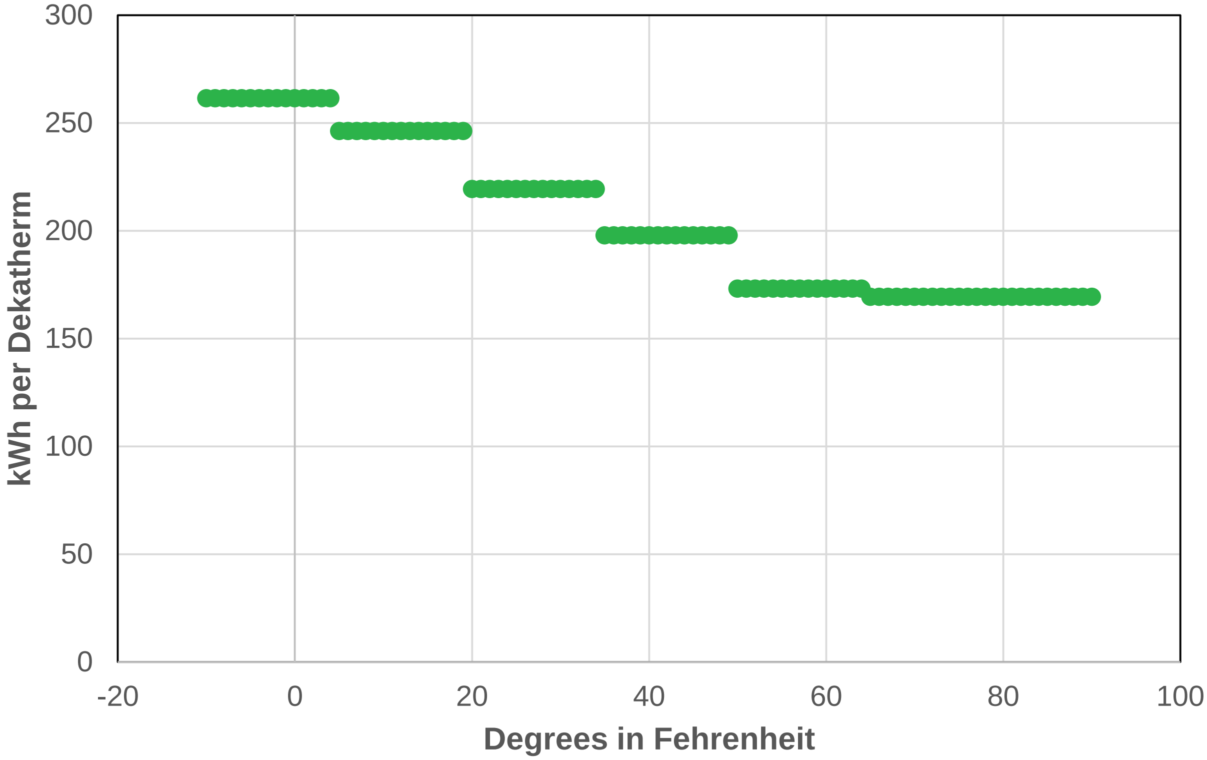
The remaining natural gas usage is for commercial/industrial processes and water heating throughout the rest of the year. The next step identifies customer classes and uses by each temperature, then finally the efficiency of each process at each temperature. For example, a heat pump is 150 percent efficient compared to strip electric heat at 35 degrees, but at five degrees Fahrenheit, the heat pump is only 100 percent efficient and assumed to be equal to strip heat or an electric furnace. Given the IRP's focus on reliability in winter peak months, the efficiency rates in cold temperatures such as 5 degrees is most important.

Figure 12.17: 2017 Avista's Core Natural Gas Load



Avista uses an estimated efficiency rate in ten-degree temperature blocks to estimate the added load, see Figure 12.18. As temperatures get colder, the amount of kWh required per therm each day increases. These estimates calculate the amount of load on the natural gas system by splitting it between water heat, space heat, and process; then assigning efficiency rates for each of the temperature periods to each end use type. For the January peak day from 2017, the 100,000 customers would require 681 MW on the peak hour. Figure 12.20 shows these estimates.

Figure 12.18: Natural Gas to Electric Efficiency Rates Based on Daily NG use



To check the reasonableness of the potential load requires additional analysis on a per customer basis. If 100,000 customers must add both an electric furnace and a water heater to their home/business, it would result in 1,000 MW of potential load just for furnaces assuming each furnace is 10 kW[2]. This assumes all the equipment was running at the same time, which is unlikely. In addition to the furnace load is the water-heating load. Water heaters are typically 5.5 kW[3] each, thus adding 550 MW if all water heaters are running totaling 1,550 MW of potential peak load. Assuming historical diversity on an average peak day[4] the new load is 681 MW, although this maximum potential could hold in lower temperature days. With higher loads, sensitivity per unit of temperature could require Avista to increase its planning margin and require additional capacity resources.

Overall, this analysis determined the load shift by estimating the average change in consumption from the total system, then backed into how the energy would be shaped by day (and by hour) based on historical natural gas usage and end uses. Avista hopes to see additional studies completed across the region to study this effect in detail and to understand the externalities resulting from major fuel changes. Figure 12.19 shows the resulting load effects of the natural gas conversions. The chart shows the steady growth

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[2] Electric furnace sizes depend on building square footage and the building envelope.
[3] Assumes the kWh required during resistance mode if the water heater is a heat pump model.
[4] An average peak day is temperature equating to the average of the historical coldest days of each year in the Spokane temperature historic record.

in winter peak to approximately 680 MW while the average energy is much smaller at 170 aMW. The summer impact is minor at around 56 aMW.

Figure 12.19: Electrification Scenario: Load with Natural Gas Customer Conversions

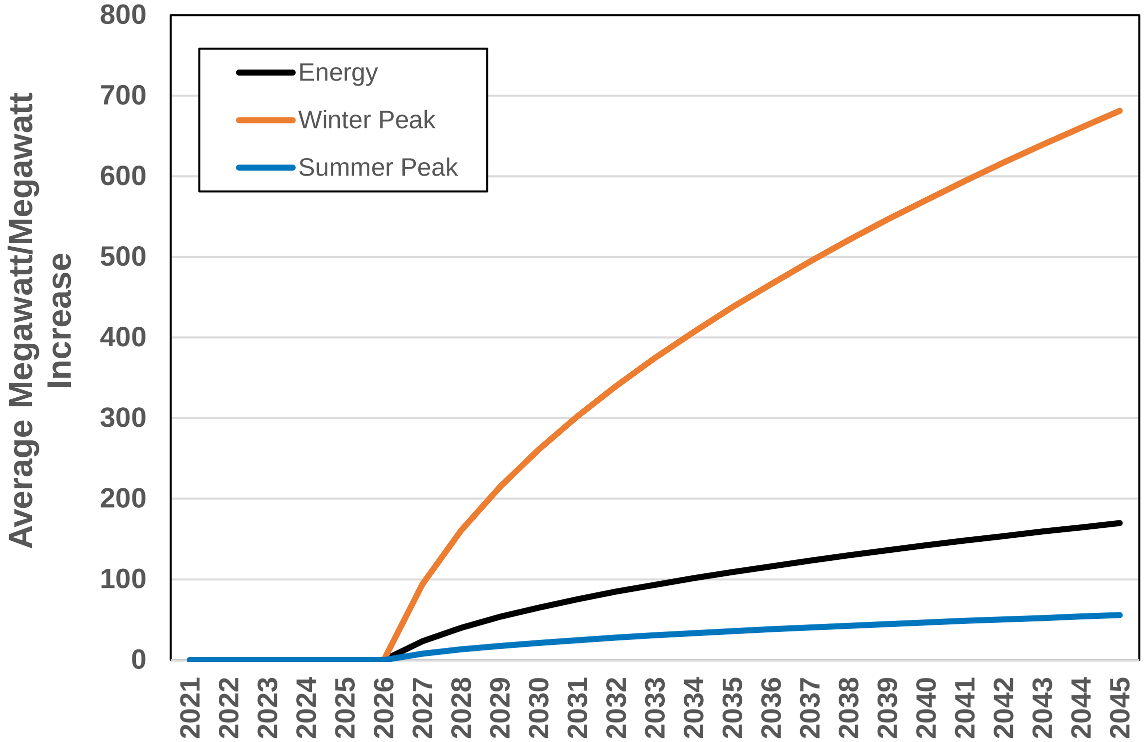
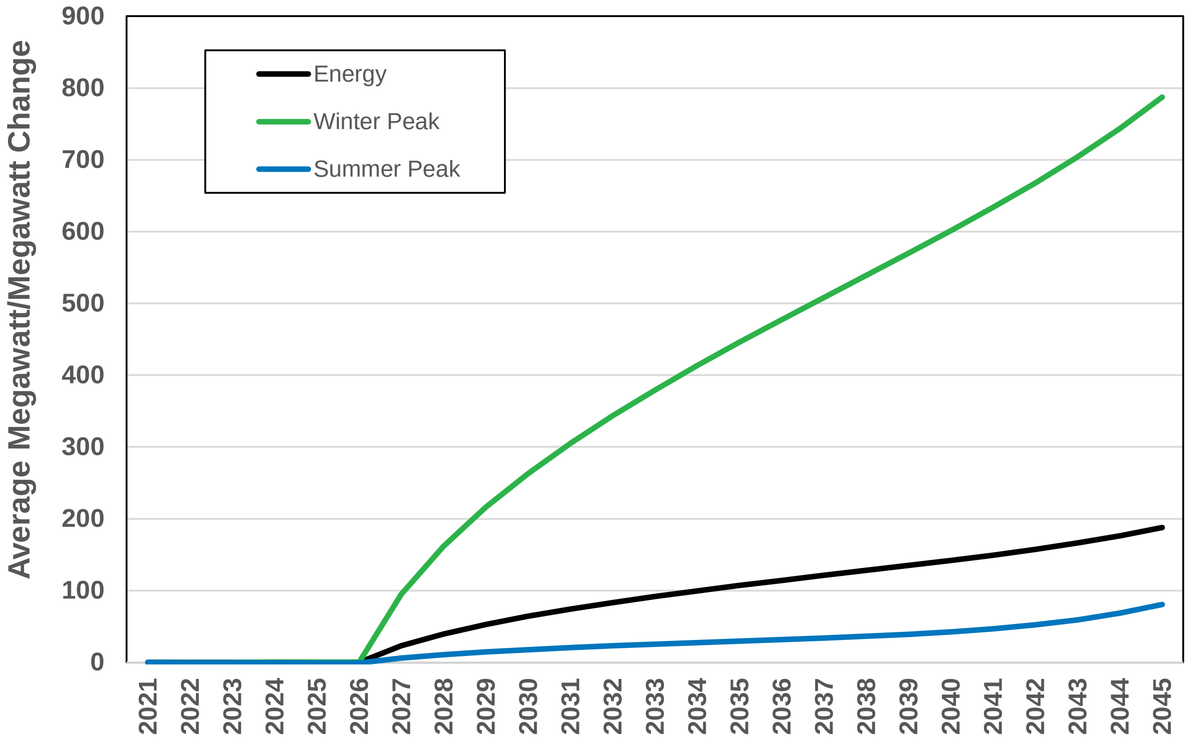


Figure 12.20 shows the total load changes for the three electrification load adjustments. The winter peak load is the largest adjustment primarily due to the heating conversions and to a smaller extent additional EVs. In 2045, the peak forecast without these adjustments is 1,882 MW; with the adjustments, the peak increases to 2,670 MW, a 42 percent increase. This analysis only converts 100,000 customers to electric, if the remaining 200,000 customers were electrified the added peak load will exceed 4,700 MW or 250 percent of the current forecast for 2045. Summer peak does not increase much due to the additional rooftop solar installations. Overall, the challenge to serve customers with this load profile is to have a reliable source of energy for meeting winter loads between October and April.

Figure 12.20: Electrification Scenario: Total Load Changes



The change in load requirements is not the only important consideration in the electrification scenario. First, there will be impacts to the remaining natural gas customers. The impacts are to the remaining customers who must pay for a system designed for a larger customer base. There will also be carbon emission reductions from the reduction in direct natural gas consumption, estimated to reach 430,000 metric tons by 2045. Additional analysis to quantify the new transmission requirements to move the new generation to the added load will be necessary. Further, each of Avista's distribution feeders could double or triple in load requirements requiring new feeders. The last impact is the cost to homeowners. Electric only customers will pay higher heating costs using current prices as compared to today's natural gas prices but also pay higher rates to construct new generation to serve the new load. In addition, there is a cost to convert residential equipment to electric and potentially a cost to rewire existing homes to handle the additional electric load. Another concern customers may have is the lack of a diversified energy source for back up. Many customers use natural gas heating in the event of storm related power outages; without this option, customers may also have to invest in new secondary heating options.

The year 2045 is the easiest to illustrate the costs and benefits to the power system for this scenario, along with the associated emission reductions, due to the earlier ramping into the end goals of load changes. The estimated cost increase in 2045 is $243 million above the cost of the PRS; this includes the avoided natural gas commodity costs but does not include the change in petroleum purchases or the cost for customer's rooftop solar systems. This cost translates to a rate of 14.8 cents per kWh, compared to 14.1

cents per kWh from the PRS. The rate impacts are less than compared to total cost divided by the additional kWh sold.

The main reason for the change in the power system cost is the cost to add new generating resources to cover peak loads and meet the clean energy goals. Although the 2045 goal of 100 percent clean energy all the time is not met as the cost exceeds the 2 percent threshold, and the storage required to meet the added loads during the winter would need to be studied for reliability analysis and would likely exceed durations in the "weeks" time period. Absent changes in technology, Avista would need an additional 700 MW of natural gas-fired turbines, 700 MW of solar with 300 MW of 4-hour lithium-ion storage, and 400 MW of liquid air storage[5]. Although even with the natural gas-fired electric generation additions, emissions would still fall, as much of this additional generation is only required during peak periods.

The emissions in the PRS, including the natural gas emissions for the 100,000 LDC customers[6], and the included emissions reductions from the avoided petroleum is a net increase of 310,000 metric tons. In the electrification scenario, utility emissions increase to just under 600,000 metric tons, but EV emissions lower by a total of 1.3 million metric tons (or an additional reduction of 770,000 metric tons); the LDC natural gas emissions reduce to zero from 430,000 metric tons. The net change in emissions is approximately one million metric tons as shown in Table 12.22. Using these estimates, the 2045 implied cost of carbon reduction is $241 per metric ton, not including the costs for the rooftop solar, additional transmission and distribution costs, and the associated customer home/business equipment conversion costs. The social cost of carbon estimate in 2045 is $179 per metric ton.

Table 12.22: Electrification Scenario: Emission Changes in Millions of Metric Tons

GHG Emissions Category	PRS + LDC Natural Gas	Electrification Scenario	Changes
Electric Utility	0.41	0.60	+0.19
Avoided Petroleum	-0.53	-1.30	-0.77
LDC Natural Gas	0.43	0.00	-0.43
Total Emissions	0.31	-0.70	-1.01

When considering the remaining 24 years of the study, the total increase in cost is $700 million or 6 percent, the total emissions reduction using the 2.5 percent discount rate equates to three million metric tons, for a 25-year average cost of $228 per metric ton[7] of carbon emissions reduction. Using the results of this study in total, the justification for electrifying all of these systems is not an effective use of customer money to reduce

[5] Avista has not conducted a reliability study to determine if this portfolio would meet reliability standards.
[6] This analysis does not consider emissions from the remaining natural gas customers.
[7] If discounted at Avista's discount rate, the emissions cost per ton would be $483 per metric ton.

greenhouse gas emissions due to the investments required for small emission reductions. Although a look at the individual electrification policies may lead to different conclusions, such as electrifying segments of the transportation sector.

The installation of rooftop solar does not affect Avista's resource strategy due to its lack of winter capacity savings. Although, rooftop solar lowers retail sales and pushes fixed costs to other customers unless there is rate reform. The case for electric vehicles seems to have potential as an effective measure of reducing greenhouse gas emissions without a material impact to the power system,[8] and depending on the cost to consumers for the transition in vehicle types, it could make the most sense for reducing regional emissions. The movement to electrify space and water heat is the most expensive endeavor of the three concepts due to the significant winter capacity requirements. Perhaps identifying additional energy efficiency, renewable natural gas systems, and potential carbon capture on end use consumption is better use of limited customer funds to make sure Avista's customers have a cost effective method of keeping warm in the winter.

[8] This insight uses Avista's current small amount of EVs on the system and its opinion may change as additional vehicles effect on the load materializes especially in the winter as additional energy/capacity may exceed current expectations.

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13. Action Items

The IRP is an ongoing and iterative process balancing regular publication timelines with pursuing the best resource strategy for the future. The biennial publication date provides opportunities to document ongoing improvements to the modeling and forecasting procedures and tools, as well as enhance the process with new research as the planning environment changes. This section provides an overview of the progress made on the 2017 IRP Action Plan and provides the 2020 Action Plan.

Summary of the 2017 IRP Action Plan

The 2017 Action Plan included three categories: generation resource related analysis, energy efficiency, and transmission planning.

Generation Resource Related Analysis

- Continue to review existing facilities for opportunities to upgrade capacity and efficiency.
    - Avista included upgrade options for this IRP analysis for Post Falls, Long Lake, Rathdrum, and Kettle Falls. This IRP also evaluated the potential for upgrades at Monroe Street, Upper Falls, and Cabinet Gorge. The results of the study were to pursue upgrades at each of the facilities studied. Avista plans to continue to enhance existing resources where possible to help meet future resource needs. Additional information regarding resource upgrades is included in Chapter 9.

- Model specific commercially available storage technologies within the IRP; including efficiency rates, capital cost, O&M, life cycle, and ability to provide non-power supply benefits.
    - This IRP includes a range of storage resource technologies and durations. The IRP studied the reliability benefits of different storage durations. Avista included pumped hydro, liquid-air, and lithium-ion in the 2020 PRS. During this IRP cycle, storage costs continued to change and new technologies are being developed. Avista will continue to analyze new storage options as a resource in addition to continuing its process in optimizing the transmission and distribution systems to utilize storage when helpful to the local system. A full list of the storage resource options and descriptions is available in Chapter 9.

- Update the TAC regarding the EIM study and Avista plan of action.
    - Avista's officers approved joining the EIM on April 15, 2019 and the Company plans to go live with the EIM on April 1, 2022. Avista shared this update at the fifth TAC meeting on October 15, 2019. As part of joining the EIM, Avista expects to spend $21 to $26 million to enter the market and an additional $3.5 to $4.0 million each year thereafter. The EIM will require at least 12 new employees to support ongoing market operations. The benefits of the EIM range from $2 to $12 million per year, but are likely to be $5.8 million per year. The complete EIM presentation shared with the TAC is in Appendix A.

- Monitor regional winter and summer resource adequacy, provide TAC with additional Avista LOLP study analysis.
    - o The second TAC meeting included a presentation regarding Avista's resource adequacy methodology and preliminary results of our system for 2030. Avista also presented the TAC with ELCC calculations for each resource used for resolving Avista capacity shortfalls. In the sixth TAC meeting, Avista shared results from the PRS's reliability analysis. Appendix A includes the slides presented to the TAC and Chapters 9 and 11 include results from Avista's reliability studies.

- Update the TAC regarding progress on the Post Falls Hydroelectric Project redevelopment.
    - o Avista concluded in the PRS analysis that the most cost effective plan for Post Falls was to redevelop the site by 2027 to maintain its Spokane River License. The project scope includes replacing turbines and generators with higher ratings to generate additional capacity and energy. Avista compared this option against replacing the equipment with similar sized technology. Avista shared this progress at the second, fifth, and sixth TAC meetings. Those presentations are available in Appendix A.

- Perform a study to determine ancillary services valuation for storage and peaking technologies using intra hour modeling capabilities. Further, use this technology to estimate costs to integrate variable resources.
    - o Avista conducted studies regarding the benefits of pumped hydro storage and flow batteries and shared results with the TAC at its fifth meeting. Avista believes this area of analysis is important to meet future needs of the system and requires tools to correctly identify the costs and benefits. Avista plans to conduct additional analysis once sub-hourly modeling is available in the ADSS system. Without this expanded ADSS functionality, the analysis will use similar methods of arriving at benefits from previous studies.

- Monitor state and federal environmental policies affecting Avista's generation fleet.
    - o Avista continues to monitor and participate in the development of state and federal environmental policies affecting Avista's generation fleet. Details providing updates about the ongoing impacts and changes to these policies are available in Chapter 4.

Energy Efficiency and Demand Response

- Determine whether or not to move the Transmission and Distribution (T&D) benefits estimate to a forward looking value versus a historical value.
    - o Avista is continuing to use the historical value method for T&D benefits with modifications to include its net plant values on a proforma basis. A forward looking methodology would be more precise as it aligns future plant values with the time period of the benefits received; however, the timing of the analysis needed to quantify future plant investments as it relates to energy efficiency becomes less reliable the further out it is forecasted. For this reason, the Company concludes a historic value method to be the preferred methodology. In order to incorporate an element of forward looking values, Avista includes its net plant on a proforma basis

to better align the values with future T&D benefit periods. For DR's potential for offsetting T&D investments, Avista needs to make progress to analyze DR potential at the feeder level or identify DR opportunities on feeders with the need for additional investment.

- Determine if a study is necessary to estimate the potential and costs for a winter and summer residential demand response program and along with an update to the existing commercial and industrial analysis.
    - Applied Energy Group (AEG) conducted a DR potential study for Avista's service territory. The study included programs for residential, commercial, and industrial customers. AEG presented the DR programs at the third TAC meeting in April 2019. Chapter 6 includes an overview of these DR programs. Avista also identified many of these programs as cost effective and they are included in the PRS described in Chapter 11.

- Use the utility cost test methodology to select conservation potential for Idaho program options.
    - Avista included the UCT methodology for evaluating energy efficiency in Idaho. Avista continues to use the TRC method in Washington. Details about energy efficiency cost methodologies are located in Chapter 5.

- Share proposed energy efficiency measure list with Advisory Groups prior to CPA completion.
    - Avista provided a list of energy efficiency measures to TAC members in April 2019. The list is also available as Appendix E.

Transmission and Distribution Planning

- Work to maintain Avista's existing transmission rights, under applicable FERC policies, for transmission service to bundled retail native load.
    - Avista has maintained its existing transmission rights on its system and any transmissions system it purchases rights from to serve native load.

- Continue to participate in BPA transmission processes and rate proceedings to minimize costs of integrating existing resources outside of Avista's service area.
    - Avista continues to actively participate in BPA transmission rate proceedings.

- Continue to participate in regional and sub-regional efforts to facilitate long-term economic expansion of the regional transmission system.
    - Avista staff participates in and leads many regional transmission efforts including the Columbia Grid and the Northern Tier Transmissions Group Forums.

- IRP & T&D planning will coordinate on evaluating opportunities for alternative technologies to solve T&D constraints.
    - Avista conducted a pilot of whether or not a distribution project could be modeled within PRiSM to co-optimize the power system along with the needs of the T&D

system. Chapter 8 discusses this analysis. Avista plans to continue this analysis in future IRPs.

2020 IRP Two Year Action Plan

Avista's 2020 PRS provides direction and guidance for the type, timing, and size of future resource acquisitions. The 2020 IRP Action Plan highlights the activities Avista will undertake between IRP filings. These activities include both resource acquisition processes, regulatory filings, and analytical efforts for the next IRP. Progress and results for the 2020 Action Plan items are reported to the TAC and the results or progress will be included in Avista's next IRP. This Action Plan includes input from Commission Staff, Avista's management team, and members of the TAC.

Resource Acquisition Action Items

- Determine the plan for Long Lake Development expansion. This includes a filing with the appropriate agencies to determine if the project upgrades identified in this plan meet CETA requirements. Begin discussions with agencies who are part of the Spokane River license to discuss expansion options. Lastly determine if the project should include a new second powerhouse, a new combined powerhouse including existing generation capacity, or leave the project unchanged. This Action Item will begin in 2020 and will be an ongoing item for the 2021 IRP. Any updates will be shared with the TAC when available.

- Avista identifies long duration pumped hydro storage as the capacity resource deficits. Avista will continue engaging with pumped hydro developers regarding this resource. Avista will investigate the potential for pumped hydro in or near its service territory for long-term potential. This Action Item will continue through future IRPs, and TAC updates will be made as new information is available.

- The resource analysis identifies a natural gas CT to replace resource deficits if pumped hydro is not a feasible resource to meet the 2026 shortfall. Avista will conduct transmission and air permitting studies to prepare for this contingency. Avista expects this process to take at least two years.

- Avista will consider releasing a renewables RFP in the second quarter of 2020 for new resources meeting the CETA requirements. Projects are preferred to be online by 2022 and 2023, but other start dates may be acceptable depending on cost effectiveness and other considerations, including final CETA rule making requirements.

- To meet the January 1, 2026 capacity shortfall and to validate Avista's preferred choice of long duration pumped hydro to meet this deficit, Avista may release a capacity RFP as early as 2021. Avista will evaluate the appropriate timing of this RFP in 2020. Potential projects will need to have a clear ability to serve Avista's customers during winter peaks. Avista anticipates existing resources, DR, renewable, thermal, and storage resources to respond.

- This IRP forecasts the Northeast CT will retire in 2035. Avista will continue to evaluate this date as it operates the facility and will provide the TAC with additional analysis and information regarding the preferred retirement date.

- This IRP's analysis determines Colstrip is best to shut down after 2025 compared to alternative scenarios, such as a 2035 closure or operating a single unit through 2035. As discussed in Chapter 12 – Portfolio Scenarios, the inclusion or exclusion of the social cost of carbon regarding Colstrip does not change the answer to the closure date. Avista will continue evaluating this analysis and work with the other owners for the course of action to meet state objectives and meet the needs of all of Avista's customers.

Analytical and Process Action Items

- Avista will continue to study the costs of intermittent resources and understand the financial benefits and capability of resources such as storage, natural gas-fired peakers, and hydroelectric resources to meet the intermittent characteristics of variable resources. Studies will continue if and when sub-hourly modeling is functional in Avista's ADSS software. Avista's timeline for this analysis is to be completed in 2021.

- Avista intends to include greenhouse gas emissions from resource construction, manufacturing, and operations where available. This research will begin in 2020 and will be shared with the TAC members at a future meeting. Avista prefers this to be a collaborative effort with the TAC members as there is no clearly accepted standard for this area of research.

- The time and resource commitment to produce the electric market price forecast is extensive and difficult to complete internally. To make the best use of staff time and customer's resources Avista will investigate early in 2020 whether or not using a third party forecast, along with an internally developed dispatch model, is a better approach to inform the resource planning effort.

- Washington State will issue rules for CETA and IRP planning over the next two years. Avista will be an active participant in this rulemaking process. The timeline is 2020-2023.

- Avista will continue to support and participate in regional resource adequacy discussions and market developments by the Northwest Power Pool and the CAISO respectively. Avista will report back to the TAC when further information is available.

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